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January 30, 2015

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-15-01
Modify Terms and Conditions of Prospective PURPA Energy Sales Agreements – Idaho Power Company's Petition and Testimony

Dear Ms. Jewell:

Enclosed for filing in the above matter please find an original and seven (7) copies of Idaho Power Company's Petition.

Also enclosed for filing are an original and eight (8) copies each of the Direct Testimony of Lisa A. Grow and Randy Allphin. One copy of each of the aforementioned testimonies has been designated as the "Reporter's Copy." In addition, a disk containing Word versions of Ms. Grow's and Mr. Allphin's testimonies is enclosed for the Reporter.

If you have any questions about the enclosed documents, please do not hesitate to contact me.

Very truly yours,

Donovan E. Walker

DEW:csb
Enclosures

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Attorney for Idaho Power Company

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PROSPECTIVE PURPA ENERGY SALES AGREEMENTS.	)	CASE NO. IPC-E-15-01 IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PROSPECTIVE PURPA ENERGY SALES AGREEMENTS

I. INTRODUCTION AND SUMMARY

Idaho Power Company ("Idaho Power" or "Company"), pursuant to RP 56, hereby respectfully petitions the Idaho Public Utilities Commission ("Commission") to issue an order modifying the terms and conditions by which Idaho Power must purchase energy generated by Qualifying Facilities ("QF") pursuant to §§ 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and various Commission orders. Idaho Power's request to modify terms and conditions for prospective PURPA energy sales agreements is limited to transactions with proposed QF projects that exceed the published rate eligibility cap.[1]

Specifically, the Company believes the continued creation of 20-year term contracts places undue risk on customers at a time when Idaho Power has sufficient resources to meet customer demands. The Company's required Integrated Resource Plan ("IRP") process is filed and updated every two years. Non-PURPA purchase and sales transactions are limited to less than two years pursuant to the Company's approved risk management policy. Avoided cost rates are updated at least every year. Therefore, Idaho Power requests that the Commission issue an order directing that the maximum required term for prospective Idaho Power PURPA energy sales agreements be reduced from 20 years to two years.

Idaho Power currently has a total of 1,302 megawatts ("MW") of PURPA QF projects under contract. Allphin, Ex. 2. Of that total, 781 MW of capacity from these projects are on-line and operational today. *Id.* Idaho Power has 577 MW of PURPA wind capacity currently operating on its system, with an additional 50 MW under contract to be on-line in 2016. *Id.* The Company has 461 MW of PURPA solar capacity under contract to be on-line in 2016, and an additional 885 MW of PURPA solar capacity in the queue actively seeking PURPA energy sales agreements to be on-line in 2016. Allphin, Ex. 1; Ex. 2. In total, Idaho Power today has 2,187 MW of PURPA generation operating, under contract, or currently requesting long-term, fixed-price energy sales agreements to be on-line in 2016. *Id.*

[1] The published rate eligibility cap is 100 kilowatts for wind and solar QFs and 10 average megawatts for all other QF generation types.

Idaho Power's customer obligation for the current 781 MW of constructed and operating QF capacity is approximately $2.6 billion over the life of the respective agreements. Allphin, Ex. 4. The additional 461 MW of approved solar QF contracts represents an additional financial obligation to be borne by customers of approximately $1.6 billion. *Id.* The addition of the 885 MW of proposed solar QF projects would represent yet another long-term financial obligation to customers of approximately $2.1 billion. *Id.* The addition of the recently proposed PURPA solar generation would take Idaho Power's and its customers' obligations under PURPA from the existing $2.6 billion to $6.4 billion of contractually obligated energy payments, all of which must be borne by Idaho Power customers. *Id.*

The Commission in its recent approval of the last 11 PURPA solar energy sales agreements has questioned the continued acquisition of such large amounts of PURPA generation when there is not an associated need for that generation on Idaho Power's system.[2] The Commission stated in those orders, "Unfortunately, PURPA does not address and FERC regulation does not adequately provide for consideration of whether the utility being forced to purchase QF power is actually in need of such energy." *See* fn. 2. Idaho Power currently has generation capacity sufficient to reliably serve customers' peak consumption, or demand, through the year 2021, and has sufficient resources to meet customers' energy consumption (monthly average) beyond the 20-year IRP planning horizon, past 2033. Order No. 33159; 2013 IRP, p. 60. Additionally, the Company's 2013 IRP has identified the Boardman to Hemingway transmission line as the primary resource in the near-term action plan. The Boardman to Hemingway

[2] Order Nos. 33198, pp. 5-7; 33199, pp. 5-7; 33200, pp. 5-7; 33201, pp. 5-6; 33202, pp. 5-6; 33204, pp. 6-7; 33205, pp. 6-7; 33206, pp. 7-8; 33207, pp. 6-8; 33208, pp. 6-8; 33209, pp. 6-8.

transmission line would serve additional growth for years beyond the next identified need in 2021 without adding any new generation plants.

The Commission expressed concern about passing those substantial costs for unneeded resources on to Idaho Power customers. The Commission concluded each of the orders, footnoted above, with expression of its concern about Idaho Power's ability to continue to take such large amounts of intermittent generation stating, "While we are pleased with the progression of the IRP methodology, avoided cost rates are not the only terms to a PURPA contract. The utilities are in the best position to inform the Commission if review of additional PURPA contract terms and conditions is warranted." *See* fn. 2.

The requested modification to terms and conditions of required PURPA energy purchases is necessary to prevent harm to Idaho Power's customers that may result from entering into additional long-term, fixed-rate purchase agreements/obligations when there is no need for such generation. Idaho Power should not be obligated to enter into prospective long-term contracts for the large amount of proposed QF solar generation, nor should Idaho Power customers be obligated to pay for such long-term purchases when there is no need for such power production.

Several issues related to the Commission's implementation of PURPA in the state of Idaho could warrant additional examination and possible revision. These items could include: (1) further modification to the existing avoided cost pricing methodologies to more appropriately reflect need and resource sufficiency in the price; (2) implementation of new avoided cost pricing methodologies which move to a market-based or competitively bid-based avoided cost mechanism, such as that utilized in

Washington; (3) exemption from PURPA under § 210, part M; (4) Commission pursuit of a waiver from the requirements of § 210, subpart C, for Idaho Power pursuant to 18 C.F.R. § 292.402; (5) refinement of the Commission's 90%/110% definition of firmness to require firm scheduled deliveries for entitlement to rates established at the time of contracting or legally enforceable obligation, as opposed to rates determined at the time of delivery, similar to the implementation in Texas; (6) further refinement of the eligibility for rates established at the time of contracting or legally enforceable obligation by requiring QFs to be within 90 days of delivering power before the utility is obligated to the price, again similar to the implementation in Texas; (7) modification of contractual term limitations; and (8) establishment of caps, or MW targets, upon the amount of new or repowered projects a utility is required to procure over a given period of time, similar to those in place in California. While the Company believes each of these issues may warrant further examination, at this time, Idaho Power's specific request with this Petition is that the Commission modify the terms and conditions of prospective purchases from PURPA QFs by reducing the current 20-year contract term for Idaho Power energy sales agreements to a maximum of two years, and direct any other relief it deems appropriate and in the public interest.

This Petition is supported by the accompanying testimony and exhibits of Lisa A. Grow and Randy Allphin as well as the previously sworn, admitted, and cross-examined Direct Testimony of William H. Hieronymus from Case No. GNR-E-11-03, attached hereto as Attachment 1, and is based on the following:

II. BACKGROUND

A. PURPA.

Sections 201 and 210 of PURPA require electric utilities to offer to purchase electric energy from qualifying cogeneration and small power production facilities. 16 USC § 824a-3(a). PURPA further specifies that the purchase rates set by state commissions for electric utility purchases of energy generated by QFs may not exceed the incremental cost to the electric utility of alternative electric energy. 16 USC § 824a-3(b). PURPA defines incremental cost as the cost to the electric utility of the electric energy which, but for the purchase from such QFs, such utility would generate or purchase from another source. 16 USC § 824a-3(d). PURPA also requires state commissions to set the rates for purchases of power from QFs at levels that are just and reasonable to the utility's customers and in the public interest and that do not discriminate against QFs, but that are not more than avoided costs. 16 USC § 824a-3(b)(1) and (2).

Congress enacted PURPA to encourage the development of cogeneration and small power production facilities, and directed the Federal Energy Regulatory Commission ("FERC") to promulgate regulations to further this goal. 16 U.S.C. § 824a-3(a); *FERC v. Mississippi*, 456 U.S. 742, 750-51, 102 S.Ct. 2126, 72 L.Ed.2d 532 (1982). PURPA also requires that the state regulatory authorities, such as the Idaho Public Utilities Commission, implement the FERC regulations. 16 U.S.C. § 824a-3(f). In *FERC v. Mississippi*, the U.S. Supreme Court found that a state may comply with its obligation to implement PURPA and FERC regulations "by issuing regulations, by resolving disputes on a case-by-case basis, or by taking any other action reasonably designed to give effect to FERC's rules." 456 U.S. at 751, 102 S.Ct. 2126, 72 L.Ed.2d 532. FERC has further stated that states may fulfill the requirement to implement its rules by "either 1) through the enactment of laws or regulations at the State level; 2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission [FERC]; or 3) by any other action reasonably designed to implement the Commission's [FERC's] rules." *Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC P 61304, 61644, 1983 WL 39627 (May 31, 1983).

The Commission has implemented the provisions of § 292.304 (Rates for Purchases) with regard to Idaho Power by making available the two pricing options referred to in § 292.304(d) at the election of the QF. First, a QF may select to sell "as available" pursuant to Idaho Power's Tariff Schedule 86, *Cogeneration and Small Power Production Non-Firm Energy*. IPUC No. 29, Tariff No. 101, Sheet No. 86-1 through 86-7. This pricing option is available for QFs selecting to receive rates based upon the utility's avoided cost at the time of delivery. Second, for QFs that select to have pricing established for a specified term according to the utility's avoided cost at the time of contracting, or when the obligation is incurred, the Commission has authorized the use of two avoided cost pricing methodologies. A surrogate avoided resource ("SAR") methodology is used for small projects below the published rate eligibility cap, currently set at 100 kilowatts for wind and solar QFs and 10 average megawatts for all other QFs. For QFs that are larger than the published rate eligibility cap, an avoided cost methodology based upon the utility's IRP is used to establish the starting point for negotiating the avoided cost rate for each specific project. The Commission reviews each QF power purchase agreement, and Commission approval of each agreement, including its prices, terms, and conditions is required prior to such agreement being effective.

B. Commission's Authority to Determine Terms of Conditions of PURPA Purchases.

The Commission has changed the authorized maximum term of a required PURPA purchase several times throughout its implementation of PURPA in the state of Idaho. The various changes to the maximum contractual term have resulted from the Commission's evaluation of changing conditions in the energy and utility environment and its attempts to balance the promotion of the development of QF resources with the cost and risk borne by Idaho Power and its customers in the transaction. From 1980 when PURPA was first implemented in the state of Idaho through 1987, utilities were obligated to provide QFs with a 35-year contract. In 1987, the Commission shortened the maximum term to 20 years based primarily upon the inherent uncertainty in long-term forecasting. Order No. 21630. In 1996, the Commission further reduced contract term to five years for QFs of 1 MW and larger, the published rate eligibility cap at that time. Order No. 26576. In 1997, the Commission extended the five-year contract term limitation to include QFs under the 1 MW published rate eligibility cap as well. Then, in 2002, the Commission went back to a 20-year contract term, which has been in place to the present. Order No. 29029.

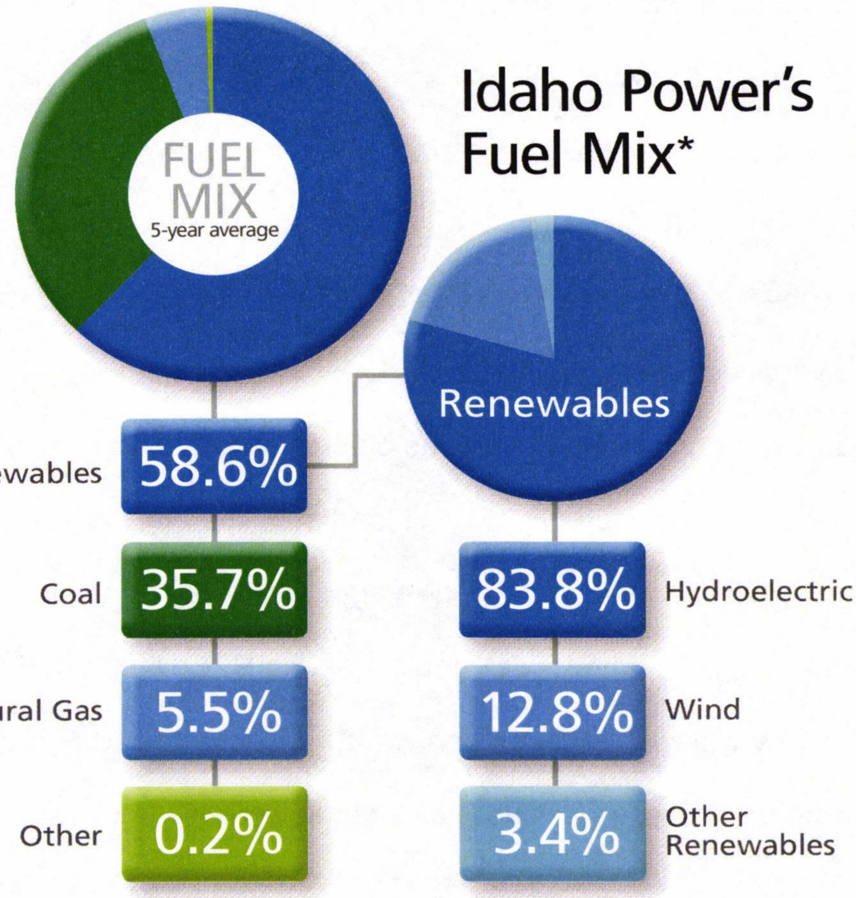
The maximum contractual term for a mandatory purchase under PURPA is an extremely important term and condition of the contract and sale. The price, terms, and conditions in a mandatory PURPA purchase, when the QF selects rates determined at the time of contracting/obligation for the duration of the contract, cannot be changed, adjusted, or effected at all, once approved and effective. FERC's view with regard to the Commission's inclusion of costs in long-term contracts was discussed in a recent Idaho Power case. *Idaho Wind Partners 1, LLC.*, Docket No. EL12-74-000, 140 FERC ¶ 61.219 (September 20, 2012)(Order Granting Petition for Declaratory Order); EL12-74-001, 143 FERC ¶ 61,248 (June 20, 2013) (Order on Rehearing). In the Idaho Wind Partners case, FERC insisted that all long-term PURPA contracts containing rates established at the time of contracting will be assumed to include all costs, even in the face of direct evidence that certain costs were not included in the avoided cost rates at the time of contracting. Order on Rehearing, *supra*. Additionally, FERC's position is that once avoided cost rates are established in the contract at the time of contracting, they cannot subsequently be changed. *Id.* While FERC's position is that the state commission may not change or revise a PURPA contract during its term because such action may constitute utility-type regulation of a QF in violation of 18 C.F.R. § 292.602(c)(1), the state commission may review and approve a PURPA contract at the time it is submitted by the parties for final approval, in furtherance of its state duty to ensure that the agreement is consistent with the public interest. *Crossroads Cogeneration Corp. v. Orange & Rockland Utilities, Inc.*, 159 F.3d 129, 138 (3d Cir.1998)("In other words, while PURPA allows the appropriate state regulatory agency to approve a power purchasing agreement, once such an agreement is approved, the state agency is not permitted to modify the terms of the agreement.").

The Commission has the obligation to ensure that the avoided cost rate and the purchase of QF generation is just and reasonable to the utility's customers, in the public interest, and that customers are not harmed by the PURPA QF obligation. Inherent in that authority is the ability to determine the appropriate term of the purchase, as well as the other terms and conditions of the purchase and sale. The Idaho Supreme Court recently upheld the Commission's authority and procedure by which it approves or disapproves PURPA power sales agreements and determines whether a legally enforceable obligation exists that would bind the QF, utility, and its customers even in the absence of a contract. *Idaho Power Co., v. Idaho Pub. Util. Comm.*, 155 Idaho 780, 316 P.3d 1278 ("*Grouse Creek*"). Determination of the proper terms and conditions of a required PURPA energy sales agreement, including the authority to determine the proper price, the proper contractual term, and the authority to approve or disapprove the contract itself is soundly, and completely, within the authority and discretion of the Commission.

C. <u>**Idaho Power's Low Carbon Emissions and Renewable Generation**</u>.

Idaho Power is a vertically integrated electric utility which began operations in 1916. Idaho Power serves more than 513,000 customers throughout a 24,000 square mile area in southern Idaho and eastern Oregon. Idaho Power owns and operates 17 hydroelectric generating facilities, primarily on the Snake River, which provide the bulk of the Company's generating ability. Idaho Power has a nameplate generation capacity of nearly 3,600 MW. Idaho Power's highest historical peak system load was nearly 3,600 MW, which occurred on July 2, 2013. The Company's peak system load for 2014 was approximately 3,184 MW. Its minimum system load for 2014 was approximately 1,073 MW. Idaho Power residential, business, and agricultural customers consistently pay some of the nation's lowest prices for electricity.

Idaho Power's five-year average fuel mix consists of over 58 percent renewables as shown in the chart below.



*Because Idaho Power does not own the Renewable Energy Certificates (REC) associated with all of these resources, we cannot and do not represent that electricity produced by this fuel mix is being delivered to our retail customers. For more information, visit our website.

Idaho Power has always been a low carbon emitting and primarily renewable energy electric utility. Idaho Power is nearly 100 years old, and its first generation facility was hydroelectric. Idaho Power believes in a diverse generation portfolio that also utilizes demand-side management and energy efficiency programs to meet the needs of its customers. As of December 31, 2014, Idaho Power had 1,428 MW of renewable energy (PURPA and non-PURPA purchases[3]) on its system or under contract, excluding the Company's hydro resources. Allphin, Ex. 2. This renewable generation consists of: 728 MW of wind, 461 MW of solar, 35 MW of geothermal, and 184 MW of small PURPA hydro and other. The state of Idaho does not have a renewable portfolio standard ("RPS"), but with only its currently existing resources the Company would meet an RPS standard of 20 percent of retail load (megawatt-hour ("MWh")) supplied by renewable energy (MWh). Allphin, Ex. 5. When Idaho Power's 1,709 MW of hydroelectric nameplate capacity is combined with the Company's acquired renewable capacity, Idaho Power has over 3,100 MW of renewable generation capacity, which equates to 90 percent of retail load supplied by renewable energy. *Id.* If the Company's PURPA generation, including PURPA solar under contract and proposed, were considered, Idaho Power would meet an RPS standard of 37 percent of retail load supplied by renewable generation, which exceeds the RPS requirements of its neighboring western states, as well as California, as shown in the graph below.[4]

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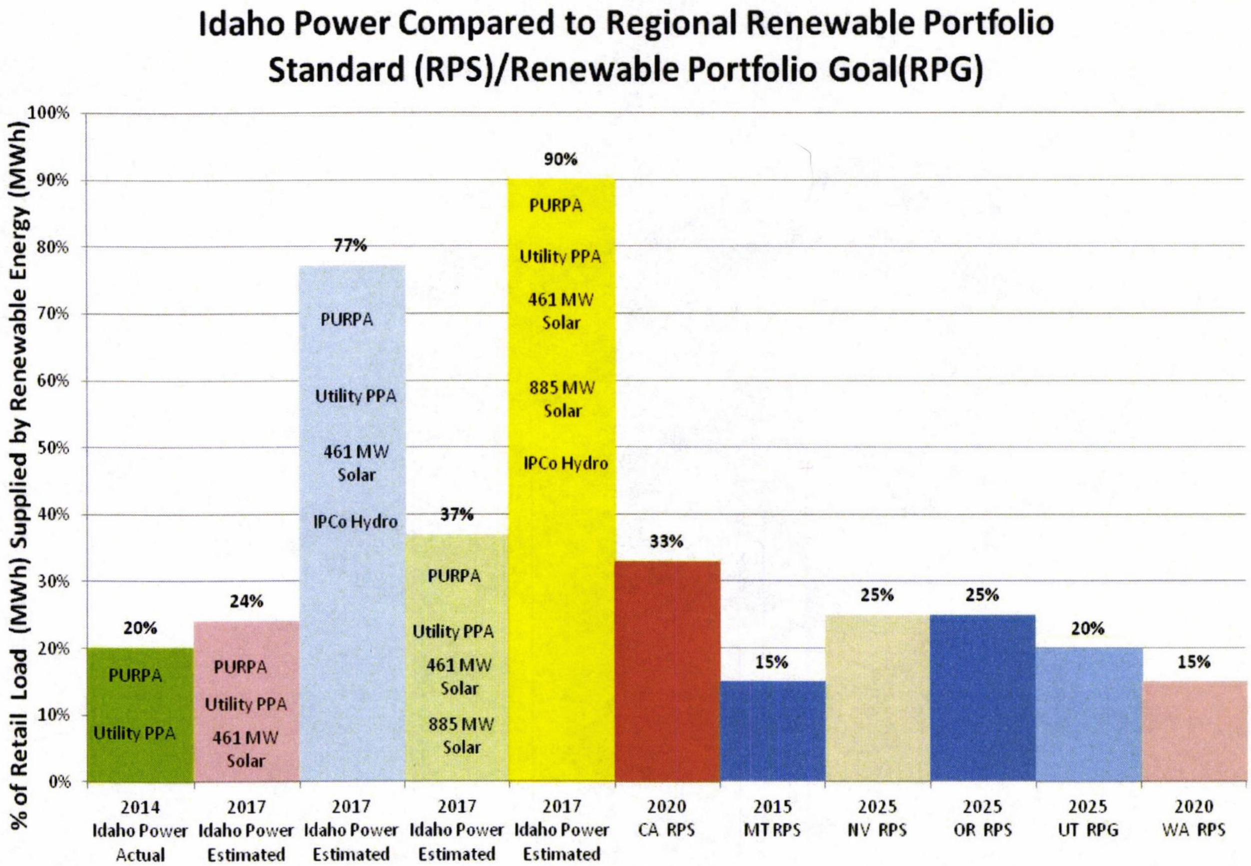
[3] Non-PURPA purchases of 136 MW include Elkhorn Wind, 101 MW; Raft River Geothermal, 13 MW; and Neal Hot Springs Geothermal, 22 MW.

[4] This comparison is done to show the magnitude of QF development and Company-owned hydro compared to various mandatory RPS requirements. Because Idaho Power does not receive the Renewable Energy Certificates/Credits ("RECs") from most of its QF generation, this generation cannot be used to meet any potential RPS requirements. Idaho Power cannot represent to customers that they are receiving renewable energy from the QFs, or from generation, for which it does not receive the RECs, and is not making any such representation here.



Idaho Power is one of the lowest carbon emitting utilities in the industry. Based upon overall 2012 emissions, Idaho Power is ranked among the 36 lowest, and, for emission intensity (per MWh), is among the 38 lowest carbon dioxide emitters among the nation's 100 largest electricity producers. Idaho Power's relative carbon emissions are set out in the chart below.

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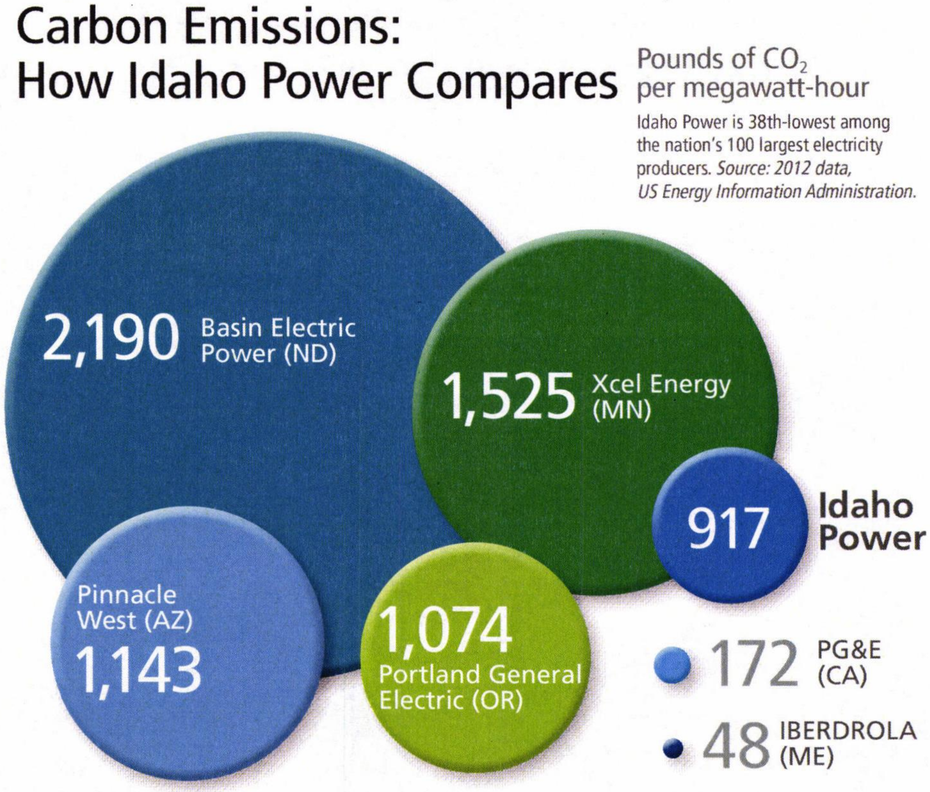

Idaho Power charts its carbon intensity in its annual sustainability reports, as well as tracking and displaying its progress on its website. Idaho Power established a carbon emission intensity goal in 2009 to reduce average carbon dioxide emission intensity for the 2010 to 2013 period by 10 to 15 percent below its 2005 intensity of 1,194 pounds per MWh. In November 2012, Idaho Power's Board of Directors approved extending that goal through 2015. By the end of 2013, Idaho Power had reduced its average carbon dioxide intensity over the 2010 to 2013 period to 929 pounds per MWh, a 22 percent reduction from 2005 carbon dioxide intensity. Preliminary results for the year ending 2014 show that the Company remains on track with approximately 944 pounds per MWh, which is a 21 percent reduction from 2005 levels.

Being a predominately hydro-based system, Idaho Power's carbon intensity varies based upon the hydrologic conditions; that is, good water years help reduce carbon emissions. However, Idaho Power has taken other steps to reduce emission intensity. The most recent addition to Idaho Power's generation is the Langley Gulch natural gas-fired plant, which was originally planned to be a coal plant, generates with about half of the carbon dioxide intensity of a coal-fired plant, helps with integration of intermittent renewable energy, and provides an option to further reduce carbon dioxide emissions and intensity by fuel switching from coal to natural gas. Idaho Power has also been working to maximize effective utilization of its existing hydroelectric resources. Recent turbine upgrades have seen efficiency gains of 3 to 5 percent increases in MW generated with the same amount of water. This also includes cloud seeding and effective water leasing practices. Idaho Power's current cloud seeding project includes 36 ground generators and an aircraft, which results in an estimated 193,000 MWh of additional hydroelectric generation. Expansion of the cloud seeding program could produce an estimated additional 277,000 MWh of hydroelectric generation.

Beyond carbon dioxide, Idaho Power has been working to reduce NO_x and SO_2 emissions from coal-fired plants and has seen a dramatic decrease in those emissions since 1998 because of enhanced operating efficiencies at the plants, improvements in pollution control equipment, and increased integration of renewable energy. In testimony from Case No. IPC-E-13-16 during 2013, Idaho Power discussed a path for the eventual retirement of coal resources. As the Company seeks to balance the impacts of carbon with the economic realities of its customers, it knows that it cannot immediately terminate operation of coal-fired plants. As the Company continues to evaluate its coal plants from an economic standpoint, from the context of 111(d), and from all relevant considerations, it is mindful that those plants have a finite life. The Company sees no new coal plants in its future as evidenced in its 2013 IRP. The Company has planned for a shutdown of its coal-fired operations at the Boardman power plant in 2020. Idaho Power has also been in discussions with the joint owner of the Valmy plant regarding the future of that plant and the resource alternatives that could replace the generation from that plant. Cost is an ongoing consideration. State public utility commissions and Idaho Power's customers demand that costs and risks be considered such that future rate increases are mitigated where possible. Idaho Power and its customers benefit from the current diversity of generation resources, and that diversity helps mitigate the power supply cost risk borne by customers as the Company transitions to the new energy landscape.

Many things have changed in the energy landscape over the last decade. The continuing emergence of carbon legislation, rules, and constraints as well as the magnitude of contracted renewable energy from PURPA require increased scrutiny. Idaho Power has been diligent to adapt the way it operates its system in order to integrate PURPA energy. At the end of the day, the Company is still obligated to produce reliable, fair-priced energy for its customers. Moreover, it has to operate within its regulatory framework, but while doing so must be conscientious as to environmental issues, cost recovery risk, and other various issues that must be considered when striking an appropriate balance.

III. DISCUSSION

A. PURPA Cogeneration and Small Power Production Has Been Successfully Encouraged and Promoted on Idaho Power's System.

Congress enacted PURPA to encourage the development of cogeneration and small power production facilities, and directed FERC to promulgate regulations to further this goal. 16 U.S.C. § 824a-3(a); *FERC v. Mississippi*, 456 U.S. 742, 750-51, 102 S.Ct. 2126, 72 L.Ed.2d 532 (1982). With the Energy Policy Act of 2005, Congress directed amendments to PURPA, which included a new Part M exempting utilities in designated Regional Transmission Organizations ("RTOs") from PURPA's purchase requirements. 42 U.S.C. § 13201, *et seq.* Additionally, federal regulations provide that any state regulatory authority, with respect to any electric utility over which it has ratemaking authority, may apply to FERC for a waiver from the application of any of the requirements of the regulation of purchases and sales between a QF and electric utilities. 18 C.F.R. § 292.402(a). FERC must grant such waiver if the state regulatory authority demonstrates that compliance with any of the requirements of the regulation of purchases and sales between a QF and electric utilities "is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA." 18 C.F.R. § 292.402(b).

Idaho Power has a long history with active PURPA QF projects. The first QF projects were constructed and started selling their output to Idaho Power under PURPA in approximately 1982. Allphin, Ex. 1. For the next 20 years, Idaho Power accumulated a large number of predominately small hydro PURPA QF projects that steadily increased and maintained energy deliveries under 200 MW total generation. *Id.* To this day, small hydro QFs make up the majority of the number of PURPA projects under contract with Idaho Power. Allphin, Ex. 2. Idaho Power has 68 PURPA hydro projects out of a total of 133 PURPA projects under contract. *Id.* PURPA hydro, however, provides a relatively small amount of the total PURPA generation. *Id.* PURPA hydro provides approximately 154 MW of the 1,302 MW of total PURPA nameplate generation capacity. *Id.* Since about 2002, and after the Commission increased the maximum contract term from five years back to 20 years (Case No. GNR-E-02-01), Idaho Power has experienced a dramatic increase in the number and size of PURPA projects, predominately wind, and now solar, QF projects coming on-line and under contract.

As shown in Mr. Allphin's Exhibit No. 2, as well as the table below, Idaho Power currently has a total of 1,302 MW of PURPA QF projects under contract. Allphin, Ex. 2. Of that total, 781 MW of capacity from these projects are on-line and operational today. *Id.* Idaho Power has 577 MW of PURPA wind capacity currently operating on its system, with an additional 50 MW under contract to be on-line in 2016. *Id.* The Company has 461 MW of PURPA solar capacity under contract to be on-line in 2016, and an additional 885 MW of PURPA solar capacity in the queue actively seeking PURPA energy sales agreements to be on-line in 2016. Allphin, Ex. 1; Ex. 2. In total, Idaho Power today has 2,187 MW of PURPA generation operating, under contract, or currently requesting long-term, fixed-price energy sales agreements to be on-line in 2016. *Id.*

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Renewable Energy

PURPA Projects		
On-line and Under Contract	**MW**	**Subtotal**
Biomass	29	
CoGen	16	
Thermal	15	
Hydro	144	
Wind	577	
	781	781
Under Contract, but NOT On-line		
Hydro	10	
Wind	50	
Solar	461	
	521	1,302
Pending (Not Under Contract, Not On-line)		
Solar	885	
	885	2,187

Non-PURPA Projects		
On-line Power Purchase Agreements	**MW**	**Subtotal**
Geothermal	35	
Wind	101	
	136	136
Total Renewable Energy - PURPA and Non-PURPA		**2,323**

Idaho Power also has an additional 136 MW of non-PURPA renewable generation under contract. The Company's non-PURPA renewable projects consist of: Elkhorn Wind, 101 MW; Neal Hot Springs Geothermal, 22 MW; Raft River Geothermal, 13 MW; and the Oregon Solar Photovoltaic Pilot Program, 55 projects with 0.42 MW. Allphin, Ex. 2.

The current customer obligation of $2.6 billion for all PURPA generation currently operating on Idaho Power's system would increase to $6.3 billion with the addition of the PURPA solar generation that is currently under contract and proposed. Allphin, Ex. 3; Ex. 4; Ex. 9. This additional obligation and risk borne by customers is being added to the Company's system at a time when it does not need any additional generation resources to serve customers' needs and when the Company already has sufficient renewable resources that would exceed the RPS requirements of Idaho Power's neighboring states and California. Allphin, Ex. 5. The purpose of encouraging and promoting the development of cogeneration and renewable power production facilities has been exceedingly met for Idaho Power.

B. The Continued Acquisition of Large Amounts of Unneeded Intermittent PURPA Generation Inflates Power Supply Costs and Degrades the Reliability of Idaho Power's System.

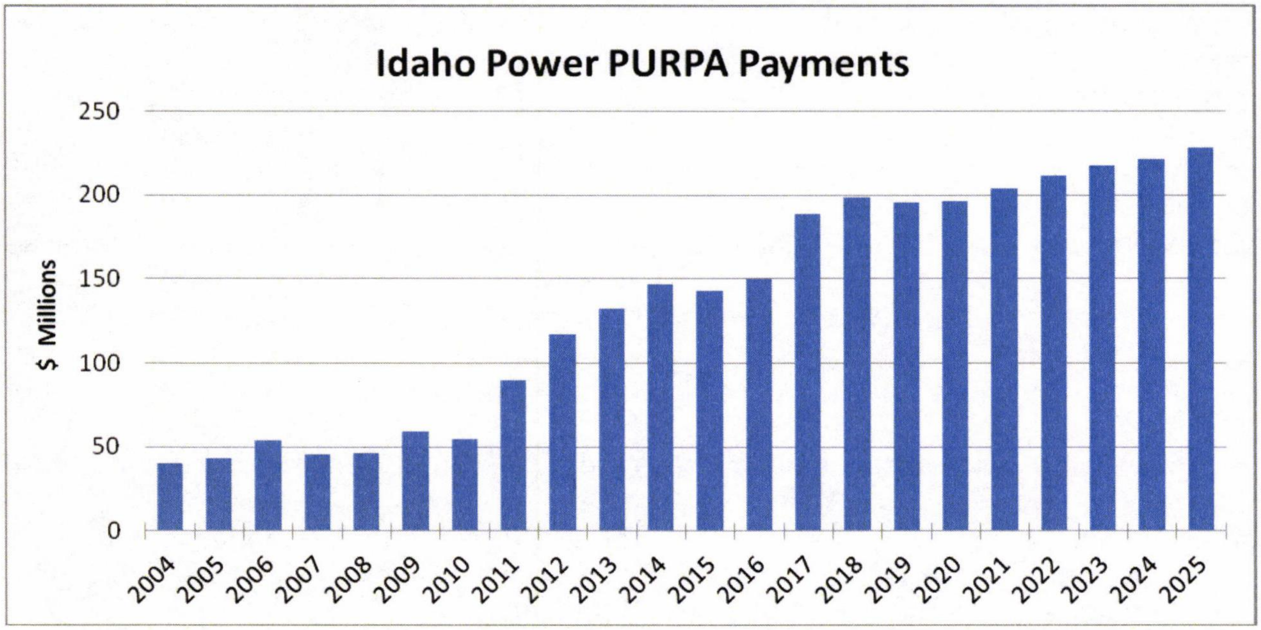
1. PURPA Power Supply Expense. PURPA requires that the price for the mandatory purchase of QF generation be set at the utility's avoided cost; i.e., the cost to the electric utility of the electric energy which, but for the purchase from such QFs, such utility would generate or purchase from another source. The Commission has recently implemented changes to the avoided cost pricing methodology for projects that exceed the published rate eligibility cap to utilize the incremental cost IRP avoided cost methodology. Order No. 32697. This methodology uses the proposed QF project's estimated hourly generation profile over a one-year period compared to Idaho Power's resource stack from its AURORA power model. For each hour that the QF proposes delivering generation to the Company, the methodology assigns the cost of the highest cost Idaho Power displaceable resource serving load in that same hour as the hourly

avoided cost. These hourly prices are accumulated into monthly heavy load and light load prices, which become the prices contained in the energy sales agreement.

The Commission stated in each of its most recent 11 orders approving PURPA solar contracts that it is pleased with the progression of the IRP methodology but that price is not the only term to the required PURPA purchase. *See* fn. 2. Idaho Power agrees with the statements. Idaho Power shares the Commission's concern that significant and substantial requests for additional energy sales agreements with PURPA QFs continue, unchecked by the pricing methodology and not burdened with meeting any requirements of need. The Commission suggested that some of the terms and conditions of PURPA energy sales agreement may need modification; Idaho Power agrees. The continued and unchecked addition of extremely large amounts of intermittent wind and solar QF generation onto Idaho Power's system at long-term, fixed-rate prices when the Company has no need for the additional generation inflates power supply costs borne by customers and degrades the reliability of the system. This is contrary to and inconsistent with all of the requirements that exist for Idaho Power to acquire non-PURPA generation resources. If the Company were to seek regulatory approval to construct 1,300 MW of solar generation, it would not be approved because of the current resource sufficiency and cost. Likewise, there is no justification for long-term PURPA contracts for that generation. Idaho Power is required to meet customer needs with the least cost, most reliable resource. Customer impacts are not held neutral when the standards for acquisition of PURPA resources are not aligned with the standards for acquisition of Company-owned resources.

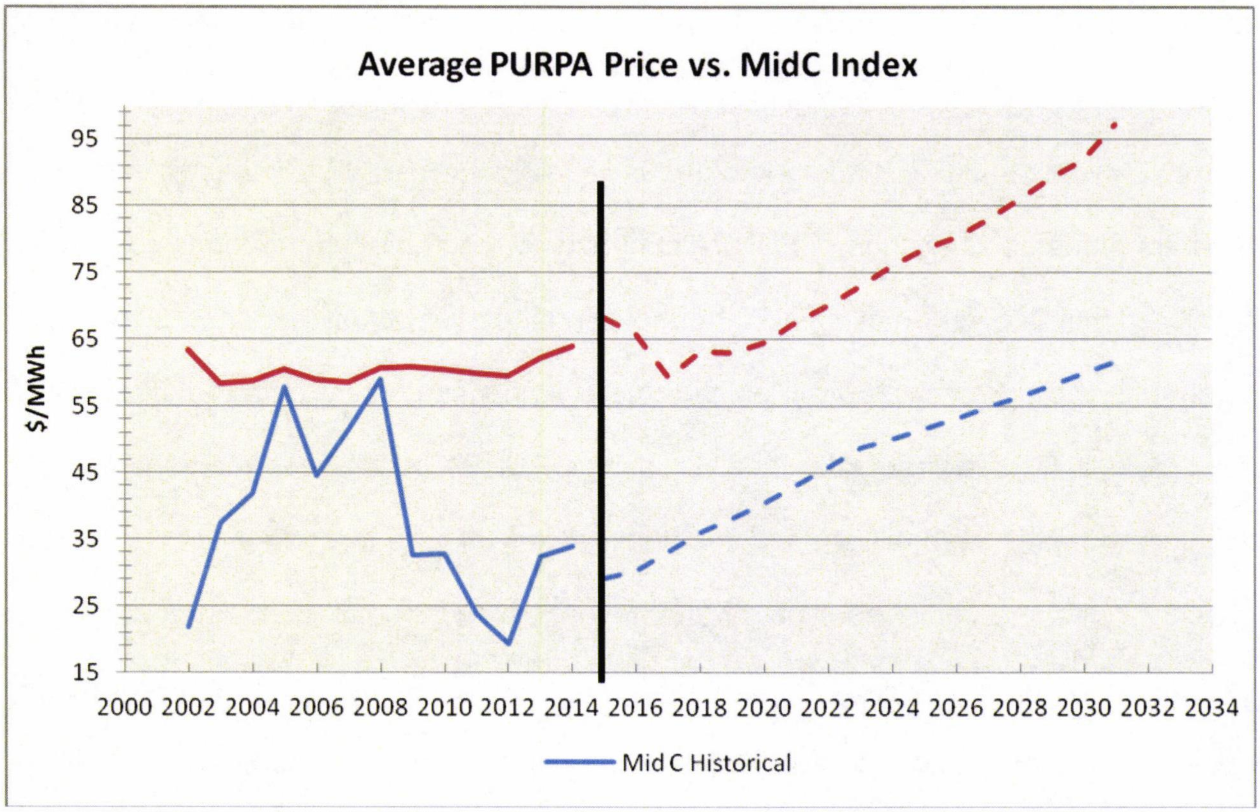
Regardless of the methodology that is employed to estimate the utility's avoided cost, it remains an estimate that will have variation from actual costs. Moreover, at a time of unprecedented changes in the technological, economic, and regulatory landscapes faced by the electric industry today, accurately forecasting future power costs is more difficult than ever. This fact, in and of itself, demonstrates why the risk and potential harm increases the longer the price estimates are locked in. This becomes compounded by federal constraints that prevent any update, change, or modification to the contractual rates, once locked in for the full term of the contract.

PURPA power supply expenses are growing at a rapid pace and becoming quite large. The graph below, which is reproduced from Mr. Allphin's Exhibit No. 7, shows the historical and projected increase in annual PURPA power supply expense from 2004 through 2025, and includes all contracts signed and approved by the Commission through December 31, 2014.



As shown in the graph above, annual PURPA power supply expenses in 2004 were approximately $40 million. Allphin, Ex. 7. 2004 approximates the beginning of the addition of large-scale PURPA wind, under 20-year, long-term, fixed-rate contracts to Idaho Power's system. The Commission increased the five-year maximum contractual term to 20 years in 2002. Order No. 29029, Case No. GNR-E-02-01. It took more than 20 years of the accumulation of PURPA contracts to reach the $40 million in costs seen in 2004. Just five years later, in 2009, the annual power supply expense grew by 50 percent to approximately $60 million. As more wind was coming onto the system at a rapid pace, just three years later, in 2012, annual PURPA power supply expense almost doubled, to nearly $120 million, and eventually levels off for a few years just under $150 million. With the rapid addition of the recent PURPA solar contracts, which are contracted to come on-line by the end of 2016, by 2018, PURPA annual power supply expense is estimated to increase to just below $200 million and increase to just under $230 million by 2025. This is a staggering 575 percent increase in annual PURPA power supply expense in approximately 20 years, over the previous 20 years. This growth trend continues during a time when Idaho Power has no identified need for new generation resources identified by its IRP. The Company is capacity sufficient through 2021, and energy sufficient beyond the next 20 years.

Idaho Power's average cost of PURPA generation included in base rates is $62.49/MWh. This price is always high when compared to current alternatives. Idaho Power's avoided cost, established through the avoided cost methodologies approved by the Commission, has historically exceeded market price, and is projected to always exceed market price into the future as shown in the graph below which is reproduced from Mr. Allphin's Exhibit No. 10.



The cost of PURPA generation contained in base rates, on a dollars per MWh basis, is not just greater than Mid-C market prices, it is greater than all the net power supply cost components currently recovered in base rates: FERC Account 501, Coal; FERC Account 547, Natural Gas; FERC Account 555, Non-PURPA Purchases; and FERC Account 447, Surplus Sales. Allphin, Ex. 8. At $62.49 per MWh, the average cost of PURPA purchases is greater than the average cost of coal at $22.79 per MWh, greater than gas at $33.57 per MWh, greater than non-PURPA purchases of $50.64 per MWh, and significantly greater than what is being sold as surplus sales at $22.41 per MWh. *Id.* This economic relationship between PURPA and the Company's other power costs illustrates that as the Company is required to purchase unneeded PURPA generation, it may be required to back down or curtail other less expensive sources of generation or market purchases in order to continue purchasing PURPA generation at a higher cost. This would mean that the Company's overall net power supply expense, on a dollars per MWh basis, would increase, adversely impacting customers.

2. Reliability of the System. The Commission stated in its recent PURPA solar orders that it was concerned about the Company's ability to balance the substantial amount of must-take intermittent generation and still reliably serve customers. *See* fn. 2. Idaho Power shares this concern. The Company already experiences reliability curtailments of generation in order to maintain reliable operations with the integration and management of the existing 781 MW of must-take PURPA generation. Idaho Power's hydroelectric and coal generation has must-run levels that the Company cannot go below without violating environmental regulations relating to the hydro facilities or taking the coal generation off-line and thus making it unavailable to meet required loads until it could be restarted. With the addition of the must-take PURPA generation, which is less predictable than firm generation and does not even equate to non-firm generation as it is unscheduled and delivered if, when, and in whatever amount the QF determines, the Company's system can rapidly move to an imbalance position, in this case over generation, and must take remedial actions. If remedial actions are not available, or not employed in a timely manner, then the Company can have system reliability violations, events, and/or outages and damage. Over the last several years, reliability curtailments of PURPA generation have been necessary in order to maintain the integrity of Idaho Power's system. For the period from May 2011 through December 2014, the Company had at least 15 reliability events that resulted in wind generation output reductions in order to maintain the reliable operation of the Company's electrical system. These curtailments, or generation

limitation set points, have been relatively infrequent, for relatively short durations, and are removed as soon as possible once it can safely be done and maintain a balanced system.

Total load on Idaho Power's system varies from a minimum of approximately 1,100 MW to a maximum of approximately 3,400 MW throughout the year.[5] Idaho Power did a comparison using the estimated system load for 2016 and 2017, including Idaho Power's must-run minimum generation from its hydro and coal generation and must-take generation from existing PURPA. This analysis is provided as Exhibit No. 6 to Mr. Allphin's direct testimony and includes a graph depicting these resources and load for the first week of each month during 2016 and 2017. Without the inclusion of any gas-fired generation, and including only the Company's must-run coal and hydro generation, without any of the must-take PURPA generation whatsoever, that generation is projected to exceed load for 14 percent of all hours during 2016 and 2017. Allphin, Ex. 6. The Company's must-run hydro and coal generation combined with existing must-take PURPA, but without any of the recently approved PURPA solar generation, exceeds total system load for approximately 29 percent of all hours during 2016 and 2017. *Id.* When the 461 MW of PURPA solar that is under contract and scheduled to be on-line in 2016 is included, Idaho Power's must-run and must-take generation exceeds total system load for approximately 33 percent of all hours in a year. *Id.* Finally, inclusion of the additional 885 MW of proposed PURPA solar generation increases the frequency of must-run and must-take generation in excess of load to 40 percent of all hours during 2016 and 2017. *Id.* Each one of these hours creates a potential over-generation event where remedial action of some kind will be

[5] Actual numbers for 2014 were approximately 1,073 MW minimum and 3,184 MW peak.

necessary to keep the system in balance and meet the obligation to reliably serve customers. The historical and projected market price for surplus sales has always been, and is projected to always be, much lower than the price the Company pays for PURPA. Allphin, Ex. 8; Ex. 10. If transmission capacity is available to conduct off-system sales, the Company would sell at a loss. Allphin, Ex. 8 (showing average cost of PURPA at $62.49 and average surplus sales price of $22.41). When the Company has no identifiable need for any additional generation, each one of these potential reliability events is a completely unnecessary destabilization of Idaho Power's system, putting its required service to its customers at risk.

C. <u>The Long-Term Lock in of Contractual Rates for 20 Years is Unjust, Unreasonable, and Contrary to the Public Interest</u>.

The state of Idaho has a chosen, authorized, and constitutional system of regulation designed to protect the public interest of the citizens of the state of Idaho and to allow for companies like Idaho Power to reliably provide a vital service to the public. *See Idaho Code* § 61-101 et. seq.; *Idaho Power & Light Co., v. Blomquist et al.*, 26 Idaho 222, 141 P.1083 (1914). Our state's system of regulation, as it pertains here to the utility acquisition of generation resources, is being undermined by PURPA.

There is a fundamental disconnection between the way a regulated monopoly service provider, like Idaho Power, must plan for and acquire generation resources and the PURPA mandatory purchase requirement. The major gap between these two regulatory processes and requirements is the determination of ***NEED***.

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IRP/Risk Management Policy/Certificate of Public Convenience and Necessity ("CPCN")	**-vs-**	**PURPA**
Meet need (load) with least cost, most reliable resource(s)		Utility + QF = FERC mandatory purchase No determination of Need, Price options at election of QF
IRP – 20-year planning horizon, refreshed every two years Request for Proposals, Competitive Bidding	**NEED**	As-Delivered – market index price, continuous term (effective until terminated on 60 day's notice)
CPCN – required to build new resources – additional scrutiny, Commission determination		20 year lock in of estimated avoided cost rate – no ability to change/adjust price
RMP – transactions do not exceed 18 months – transactions of 2 years or more, Commission approval		Commission approval or rejection of contract – or – Commission determination of legally enforceable obligation

As a regulated utility providing retail electric service to consumers in the state of Idaho, Idaho Power has strict requirements it must meet in order to acquire generation resources, which are set and overseen by the Commission. In order to acquire generation resources Idaho Power either (1) builds a generation resource that it owns and operates for the benefit of its customers or (2) purchases generation through a bilateral contract with another entity, makes a market purchase, and makes mandatory PURPA QF purchases.

Under the requirements of the Commission's regulation, Idaho Power's acquisition of utility-owned generation starts with the IRP process. The IRP must identify a need for a generation resource, and further identify the proper resource to meet that need in the least cost, most reliable manner, given the known environmental, operational, and other constraints. Then the utility would conduct a request for proposals and a competitive bidding process to select the most appropriate resource to bring to the Commission for approval. In order to construct new generation resources, the Company must obtain a CPCN from the Commission for that resource. *Idaho Code* § 61-526. Beyond the Commission's required public and regulatory processes associated with the IRP, the CPCN process subjects the decision to acquire that resource to additional Commission and public scrutiny, and assures that the utility only acquires those resources that serve a need in the least cost, most reliable manner available, and that acquisition of that resource is in the public interest. Additionally, should a proposed resource make it through the IRP and CPCN processes, there are additional Commission proceedings required to include the cost of that resource into rates and establish how those costs will be passed on to customers. The IRP is filed with and reviewed by the Commission every two years. Changes in conditions, positions, market prices, gas forecasts, load forecasts, etc., are incorporated and captured continually as they happen during the continuous development of the IRP and its every other year filing. Those decisions and inputs are not locked in for 20 years with no ability to adjust, update, or change, like PURPA transactions.

With regard to market purchases of generation resources to serve load or any other energy market transactions of purchases and sales that the Company conducts, it must comply with the Commission-approved risk management policy. The Company's risk management policy, set up to govern the risk and customer exposure to market fluctuations when the Company makes power purchases and sales on the market has short-term limitations. Under its authorized and required risk management policy, the Company does not enter into transactions beyond 18 months. If the Company were to desire to transact for any periods of two years or more, specific Commission authorization and approval is required. This policy has been deemed a prudent process for managing customer exposure to the market and transactional risk with making generation purchases and sales, and the prudent term is far below the 20 years required for mandatory, unchangeable PURPA purchases.

In stark contrast to the many Commission processes, proceedings, and protections that are in place and required for the utility to construct, own, and operate a generation resource for the benefit of its customers, the PURPA transaction has none. The only requirement in the mandatory PURPA purchase of generation is that Idaho Power is a regulated public utility providing retail service to customers and the other party is a PURPA QF. If so, and regardless of whether the resource is needed or not, the utility must purchase the generation. PURPA contains no guidance and no limitations as to whether or not the utility actually needs the QF generation resource that it is required to purchase. Similarly, PURPA contains no limit or cap on the amount of PURPA QF generation that the utility must purchase under that mandatory obligation of PURPA. These problems are amplified and exacerbated where the utility is required to purchase for a long term with fixed rates.

D. **<u>The Commission Should Reduce the Currently Authorized 20-Year Contractual Term to a Maximum of Two Years</u>.**

As referenced above, the Commission has changed the authorized maximum term of a required PURPA purchase several times throughout is implementation of PURPA in the state of Idaho The Commission has authorized maximum contract terms varying from an initial 35-year contract, to 20 years, then five years, then back to 20 years. Since the currently authorized 20-year contract term has been in place (2002), Idaho Power has seen waves of rapid, large-scale additions of wind, and now solar, QF generation.

A major consideration that must go into the determination of the appropriate maximum contract term must be the fact that once a contract is approved and put in place by the Commission that it is an absolute lock in of the rates included in that contract for the entire term. It does not matter to what extent or degree the contractual rates vary from actual, vary from changed forecasts or assumptions, or any other changed circumstances. The contractual obligation is set and fixed for the entire duration of the term of that contract. Coupled with the reality that the one-sided mandatory purchase is initiated by the QF if and when the QF determines, when the right set of conditions around price, forecasts, fluctuations in natural gas prices, etc., are most favorable to the QF, these long-term obligations are almost always locked in to the detriment of Idaho Power and its customers.

The Company is not able to acquire any other generation or purchased power that is indiscriminately locked in for such long terms. If the Company does acquire any non-PURPA generation or purchases longer than two years, it comes with specific Commission determinations of meeting a need in the least cost, most reliable manner available. These determinations are made only after careful examination and process, including various public processes and proceedings, such as through the IRP process, a CPCN proceeding, rate base proceedings, and other specific Commission proceedings and determinations that assure customers are protected and the Company meets its obligations to reliably serve. It does not follow that a PURPA transaction, that does not have the benefit, requirement, or protections associated with all of the previously mentioned Commission processes and procedures, and must be acquired regardless of need, would be indiscriminately locked in with long-term, fixed costs.

The IRP utilizes a 20-year planning horizon. At first blush, this appears to coincide with the 20-year term of a required PURPA transaction. However, this is definitely not the case. The IRP is continually updated, refreshed, and, if necessary, changed. The IRP incorporates public input into its development and is filed for the Commission's review and acknowledgment every two years. The only way that the Commission could assure that a mandatory PURPA contractual transaction would get refreshed at least as often, would be to limit the maximum term to two years. The Company's obligation to purchase from the QF would remain after the two year term, but changed circumstances, inputs, forecasts, and prices could be incorporated into the mandatory purchase, and not locked in for 20 years based upon forecasts and assumptions that can quickly become stale and disconnected from reality.

It is not just the IRP in which it has been deemed prudent to update prices and transactions on a basis more frequently than 20 years. As previously discussed, the Company does not enter into transactions past 18 months pursuant to its approved risk management policy and transactions for any periods of two years or more require specific Commission authorization and approval. It has been deemed prudent and in the public interest to update and refresh the IRP and its decisions about the need to acquire additional generation every two years. Similarly, it has been deemed prudent and in the public interest not to expose customers to market and price risk in non-

PURPA purchase and sales transactions under the Company's approved risk management policy. The risk and exposure that customers are exposed to with a required PURPA transaction is even greater because of the federal constraints that prohibit the adjustment of rates and contractual terms for the duration of the contractual term, once put in place. The authorized maximum term for PURPA energy sales agreements with Idaho Power should be limited to two years, to better align with the exposure of customers to risk that has been deemed prudent for the IRP process and the Company's risk management policy.

In PURPA exempt jurisdictions such as RTOs where utilities are exempt from PURPA's mandatory purchase, QFs and other independent power producers do not have access to 20-year, long-term, fixed-price transactions. Attachment 1 hereto contains a copy of the previously sworn, admitted, and cross-examined direct testimony of William H. Hieronymus from Case No. GNR-E-11-03. Mr. Hieronymus provided testimony regarding various implementations of PURPA throughout the country, including discussion of alternative market-based avoided cost mechanisms and available transactions in PURPA exempt jurisdictions. He testified, "No RTO requires any load serving entity to purchase energy bilaterally on a long-term basis and the longest term for a guaranteed capacity price in any RTO is three years." Hieronymus, Direct, p. 56. Mr. Hieronymus, in discussing visible market prices for calculating avoided cost prices, testified about the lack of availability of long-term transactions for QF-type projects in PURPA exempt jurisdictions:

> the Energy Policy Act of 2005 mandated that utilities in the five original RTOs were eligible for exemption from PURPA section 210 altogether. Hence, projects that previously would have been QFs in those areas are dependent on

> either bilateral contracts with utilities or the visible markets conducted by the RTOs for revenue. Most such contracts are short run in nature; state-supervised auctions typically are for three years or less. RTO power markets are even shorter term, with prices varying even within the hour and prices set at most a day ahead. Capacity typically is bought on a monthly, seasonal, or annual basis in those RTOs that have capacity markets. Power markets are also used in several instances to set avoided cost rates where the utility is not exempt. California is one example. Energy prices for QFs except the smallest ones are set based on one year forward market prices.

Hieronymus, Direct, pp. 83-84. Mr. Hieronymus also testified about how California revised its state PURPA implementation in response to overwhelming amounts of proposed PURA generation that exceeded 16,000 MW. *Id.*, pp. 72-83. Energy payments during the term of QF contracts in California are reset annually, rather than fixed in advance for the term of the contract. *Id.,* pp. 78-79.

When looking at the present amount of PURPA solar generation that has contracted with or is seeking to contract with Idaho Power, the additional obligation, risk, and price differential between a 20-year and a two-year fixed-price contract term is staggering. The 461 MW of PURPA solar currently under contract has a 20-year obligation of approximately $1,665,000,000. Allphin, Ex. 4; Ex. 9. The same 461 MW of PURPA solar would have an associated obligation passed on to customers if limited to a two-year term of $92,834,000. Allphin, Ex. 9. The 885 MW of proposed PURPA solar contains an estimated 20-year obligation of approximately $2,102,000,000, whereas the total obligation for the same 885 of proposed PURPA solar with a two-year term is approximately $103,600,000. Allphin, Ex. 3; Ex. 4.

IV. CONCLUSION

The required term of a mandatory purchase of PURPA generation is within the authority and discretion of the Commission to determine and set. The Commission has modified the required term of PURPA purchases several times in the past, and most recently implemented a 20-year maximum term in 2002. Since that time, Idaho Power has seen exponential growth in the addition of must-take PURPA generation, primarily in large rapid waves of PURPA wind and solar generation. This will inflate annual PURPA power supply expenses by more than 575 percent over 2004 levels, and has come at a cost to system reliability and to Idaho Power's customers. Idaho Power now has 2,187 MW of PURPA generation on-line, under contract, or proposed for its system—a system that has minimum loads of approximately 1,100 MW and maximum peak loads of approximately 3,400 MW. The purpose of promoting and encouraging the development of cogeneration and small power production has been met for Idaho Power.

Idaho Power has no currently identifiable need to acquire additional generation. The Company is capacity sufficient through 2021, and energy sufficient through 2035. Additionally, the planned Boardman to Hemingway transmission line would serve additional growth for years beyond that without adding any new power plants. The Company's currently existing must-run coal and hydro generation, along with currently existing and operating must-take PURPA generation (without the inclusion of any solar) exceeds estimated total system load for 29 percent of all hours during 2016 and 2017. The addition of the 461 MW of PURPA solar under contract increases the frequency of must-run and must-take generation that exceeds load to 32 percent of all hours during 2016 and 2017, while the addition of 1346 MW of the additional PURPA solar generation both under contract and proposed increases that frequency to 40 percent of all hours. Each one of these hours creates a potential over-generation event where remedial action of some kind will be necessary to keep the system in balance and meet the obligation to reliably serve customers. When the Company has no identifiable need for any additional generation, each one of these potential reliability events is a completely unnecessary destabilization of Idaho Power's system, putting its required service to its customers at risk.

The acquisition of any Company-owned generation resource, as well as the Company's purchase and sale of non-PURPA generation, is either limited to terms less than two years or is subject to intensive Commission and public participation, scrutiny, process, and proceedings to determine that the Company is acting prudently, in the public interest, and fulfilling a need in the least cost, most reliable manner possible. These requirements, particularly that of establishing need for the resource, are absent in a mandatory PURPA QF purchase. The further constraint imposed by PURPA that eliminates any ability to modify, adjust, or change the prices that are locked into a PURPA energy sales agreement for the duration of that contract's terms, regardless of whether all costs were included or whether actual costs and conditions changed or varied, makes long-term, 20-year contract terms at best risky, and in Idaho Power's case harmful.

V. PRAYER FOR RELIEF

WHEREFORE, Idaho Power respectfully requests:

1. That the Commission issue an order directing that the maximum required term for any Idaho Power PURPA energy sales agreement be reduced from 20 years to two years; and

2. That the Commission direct any other relief deemed appropriate and in the public interest.

Respectfully submitted this 30th day of January 2015.

DONOVAN E. WALKER
Attorney for Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-15-01

IDAHO POWER COMPANY

ATTACHMENT 1

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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WILLIAM H. HIERONYMUS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William H. Hieronymus and my business address is 200 Clarendon Street, T-32, Boston, Massachusetts 02116.

Q. By whom are you employed and in what capacity?

A. I am a Vice President of Charles River Associates, Inc., an international economics and management consulting company.

Q. Please describe your educational background and work experience.

A. I am an economist with a doctoral degree from the University of Michigan and have spent the past 36 years specializing in the economics and regulation of electric utilities. I have worked extensively with utilities throughout the U.S. and abroad on matters such as system planning, assets valuation, rate design, procurement design, risk management, load forecasting, and response to regulatory policies. I have testified numerous times before state utility commissions, the Federal Energy Regulatory Commission ("FERC"), courts, arbitrators, and legislative bodies on these topics and on policy matters such as price regulation, competitive market design, market power, the prudence of utility decisions, stranded costs, and so forth. In the 1980s I helped utilities and regulators in complying with the requirements of Public Utility Regulatory Policies Act of 1978 ("PURPA"). This included compliance with PURPA Section 210 that governed purchases from and sales to qualifying facilities ("QF"). My resume is attached as Exhibit No. 6.

Q. What is the purpose of your testimony in this matter?

A. I have been asked by Idaho Power Company ("Idaho Power" or "IPC") to provide an overview of experience with PURPA Section 210 and to suggest lessons relevant to the Idaho Public Utilities Commission's ("Commission") current review and reconsideration of its PURPA Section 210 implementation. While I am generally aware of Idaho's recent and current PURPA implementation and experience, I also recognize that Idaho PURPA history is very familiar to the Commission and participants in this proceeding. Hence, my focus is not primarily on the Idaho experience but rather on experience with PURPA generally.

I also have been advised that the predominant focus of this phase of the Commission's reconsideration of PURPA implementation is on the methodology for computing avoided costs and the application of it to QFs of different sizes and types. Accordingly, my testimony focuses on avoided cost methodology and its application. I also understand that the scope of consideration of avoided cost does not extend to market-based methods for meeting PURPA requirements, such as competitive procurements of power supplies and payment of market prices as alternatives to administrative/regulatory methods of setting avoided cost prices. I nonetheless will discuss use of these methods for two reasons. First, Idaho may choose to consider their use to at least some degree. Second, the fact that such methods can and have been used to satisfy the requirements of PURPA Section 210 illuminates what the section requires and hence provides guidance concerning what is essential (and non-essential or even inappropriate) if administrative avoided cost methods as designed for PURPA compliance.

Consistency between the requirements of PURPA and state implementations of Section 210 depends primarily on how avoided cost is defined and implemented. However, aspects of state implementation other than avoided cost calculation are at least as critical to the consequences of PURPA, particularly elements of implementation that affect the risk that QF payments will diverge substantially from actual avoided costs for prolonged periods as well as the related risk that Idaho utilities will be compelled to contract for QF power in amounts that materially exceed their needs. I therefore also will discuss experience with and concepts relating to these other aspects of PURPA implementation.

Lastly, I have been asked to review and comment upon Idaho Power's proposal for a new avoided cost methodology to be used in Idaho.

Q. Could you summarize how your testimony is presented?

A. Yes. I first will summarize my conclusions and recommendations. This section also contains the results of my review of the Idaho Power proposal for changes from the current avoided cost methodology. Next, I will discuss the historical development of PURPA implementation and how it has changed and evolved over time. I then will discuss various types of avoided cost methodologies employed by different states and regions to meet the requirements of PURPA. I then make recommendations regarding proper methodologies for establishing avoided cost rates, and make suggestions for a proper implementation of an administrative/regulation-based avoided cost calculation. I also discuss other issues related to power purchase agreements with PURPA QFs, particularly the risk allocation and/or risk shifting between the QF developer and the utility's customers which relates to the length of the contractual term and nature of the pricing mechanism in the contract.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Could you please summarize the conclusions and recommendations of your testimony?

A. Yes. My testimony will discuss and conclude that:

1. It is essential to not lose sight of the purpose of PURPA which was limited to ending discrimination against cogeneration and small renewable power facilities. This limited purpose is underscored by the statutory provision that prices paid shall not exceed the utility's avoided cost. Not only was PURPA not meant to subsidize QFs at the expense of customers, such subsidies are in fact illegal if provided through PURPA QF prices.

2. Avoiding large differences between PURPA rates set when contracts are signed and actual avoided cost is very important. History demonstrates that, overall, prices paid for PURPA power much exceeded costs. This arose in part from a pro-QF regulatory bias in at least some states, but also from unfortunate large errors in fuel and power market forecasts. Such large errors are harmful whether prices are too high or too low. The errors that occurred caused high profits for developers and unnecessarily high prices for consumers. Had the errors

been in the other direction, ratepayers would have had a windfall, at least until projects went bankrupt.

3. While some methods of setting avoided costs are better than others and may reduce the range of forecast error, no method of setting avoided cost can prevent the potential for large forecast errors. The only way to limit the difference between the actual value of QF power and prices paid for it is to keep contracts short and/or severely limit the period for which prices are fixed. This can be done in a number of ways, including reopeners and indexation.

4. The risk of getting prices badly wrong is compounded by the difficulty of limiting the quantity of QF power. PURPA provides no direct authority to limit QF purchases to the amount and type of power that is needed. However, solutions have been found that substantially mitigate this open-ended obligation.

5. If prices paid are not only too high but also higher than those paid in other jurisdictions, the excess QF power seeking contracts in the high rate states will be intensified. PURPA initially was focused on cogeneration, which was thought to require a real host user of steam and heat. Such hosts were immobile and limited in number. In fact, PURPA project development has turned out to be quite portable, with developers building where

conditions such as avoided cost rates and contract terms are most attractive.

6. All states, at least initially, used administrative methods/regulatory proceedings to set avoided costs. This was reasonable and necessary given the vertical integration of utilities and the lack of competitive or transparent markets for power. Unhappy experience with administratively set avoided costs in the early years after PURPA caused FERC and many utilities and state regulatory commissions to seek alternatives, primarily structured procurements such as requests for proposals and "auctions" to select QF and other third-party power projects.

7. Many states first adopted proxy unit methods that used the cost of either the next planned utility unit or a generic unit to establish avoided costs. This made logical sense given that utility planning was primarily driven by capacity needs. However, it led increasingly to mismatches between the costs avoided by not building the proxy units and the costs avoided by the QF as the nature of QFs changed from primarily QFs that operated like the conventional utility units used as proxies to quite dissimilar plant, such as energy limited, intermittent energy producers. The Idaho Surrogate Avoided Resource ("SAR") methodology is a proxy unit method.

8. The other common administrative method of establishing avoided cost is to use actual simulation of the utility system to establish avoided cost, particularly avoided energy costs. A common version uses the net cost of a peaker to establish capacity cost and simulation of operation of the utility's system to establish marginal energy costs. QF avoided cost rates are then based on the QF's forecasted capacity contribution and the amount and timing of its energy production. A more complete and complex version of this methodology simulates operation of the system with and without the QF. Avoided energy costs is the difference "with and without" the QF; avoided capacity costs may reflect changes in the resource plan as it is adjusted to accommodate the QF. These simulation-based methods are an important improvement on the proxy unit method because they inherently base avoided costs on the output characteristics of the QF. What Idaho Power calls the Integrated Resource Plan ("IRP") methodology (both currently and as proposed) is a version of this methodology.

9. Another issue concerning PURPA compliance is the use of fixed rate schedules to pay for QF power. PURPA requires such schedules only for projects of 100 kilowatts ("kW") or less, but many states have extended fixed offers to much larger units. In many instances, the

schedule is based on a proxy unit. Use of such schedules should be sharply limited for two reasons: (a) the price derived from a single proxy unit may be very unrepresentative of the value of a particular QF and (b) such inaccurate schedules can contribute to substantial excesses of QF projects demanding contracts. This problem is best mitigated by a combination of limiting the size of projects that are eligible and by having multiple standard offers, such that one of them reasonably corresponds to the actual characteristics of the QF.

10. In enacting PURPA, Congress did not anticipate the substantial restructuring of the utility industry that took place in the 1990s. In much of the country, restructuring made PURPA section 210 both onerous and unnecessary. When it enacted the Energy Policy Act of 2005, which exempted utilities in regions with visible and competitive organized power markets, Congress reinforced that the intent of PURPA was only to assure non-discriminatory treatment of QFs. The Act not only eliminated PURPA obligations for utilities serving more than half of the country, it also showed that Congress believed that access to market prices was by itself sufficient to comply with PURPA. This conclusion provides important guidance on Congressional intent to those parts of the country to which the exemption does not apply.

11. There now are multiple ways of setting PURPA avoided costs including two market methods: (a) access to competitive power markets and (b) the creation of competitive procurements, and at least two types of administrative determinations: (a) proxy units and (b) IRP/system simulation methods. Market methods, where available and applicable, have the virtue that they take the potential for bias in setting avoided cost out of the equation and reduce the amount of regulatory judgment required. In exempt regions, and in some other cases, a demonstration of QF access to markets has been sufficient to relieve the utility from all cost risks for QF power. Among administrative methods, the IRP/system simulation methods have the considerable virtue that the energy savings attributed to the QF are calculated directly from the dispatch of the QF rather than assuming counterfactually that its characteristics are those of a quite dissimilar proxy unit. While more complicated than proxy unit methods, simulation is within the capability of all utilities and is particularly appropriate when non-dispatchable, intermittent resources are a major source of QF offers. The virtue of the proxy method is that it is simple and relatively transparent.

12. My advice to the Idaho Commission concerning how to set avoided costs using

administrative/regulatory methods flows directly from these observations:

a. Use avoided cost calculation methods that take into account the characteristics of the QF unit and accurately model the timing, dispatchability, firmness and amount of power produced by the QF at issue. This requires using IRP-type methods for each unit or, in the case of small units, creating IRP-based standard offers based on the characteristics of similar generic units. It also requires time differentiation of payments.

b. Sharply limit the applicability of fixed standard offer price schedules, which PURPA only requires for QFs of less than 100 kW. If Idaho chooses to extend standard offers to larger units, it is even more important that multiple, technology-specific standard offers be developed and used so as to avoid systematic biases in avoided cost rates and unlawful discrimination among QFs and between QFs and other resources.

c. Limit capacity payments to the amount of capacity the QF actually displaces. When no capacity is displaced, the payment should be zero.

d. Limit customers' exposure to long-term price risk by such mechanisms as not offering fixed prices, using formula rates indexed to actual energy or fuels prices, and shortened contract lengths. It is particularly important that consumers not take on price risk for QF power that is not even used to serve them, but rather is sold into the interchange market.

e. Seek to limit purchases of unneeded QF energy and capacity. Quantity-limited requests for proposals ("RFP") and auctions is one way to do this. Properly reflecting the value of the specific QFs is another. For price rationing to work, it is necessary that avoided costs be reset as often as is necessary to reflect the impact of prior QFs on avoided energy and capacity values. Rationing based on pricing aside, this also is necessary if avoided costs are to be computed properly. FERC has noted that the attraction of too much QF power is a signal that prices being paid are too high and should be reduced. Including the successive amounts of QF power in the calculation is one way to do this, albeit not necessarily sufficiently.

Q. You stated earlier that you had reviewed and would comment on IPC's proposed changes to its QF avoided cost rates and tariff provisions. What do you conclude based on that review?

A. I have reviewed Idaho Power's proposal for revising the Idaho avoided cost calculation and contract terms. My review is at a relatively high level and does not extend to some of the details in it. I conclude the following:

1. The fact that QFs in amounts well in excess of what IPC can use have requested (and in many cases received) long-term contracts at fixed prices strongly indicates that IPC's avoided cost rates are too high and need reforming. I understand further that the QFs primarily have been wind farms and that most of them have availed themselves of SAR-based standard contracts, which indicates that the standard contract price in particular is too high. I agree with IPC's conclusion that reform is required urgently.

2. I support the proposed use of the "IRP method," essentially the use of a system simulation, to determine the energy price component for all QF contracts. I note that IPC proposes to base technology-specific standard offers on IRP analysis of generic units of each of the major anticipated types of QFs. I strongly agree with this approach.

3. The ceiling size of QFs eligible for standard offers that was reduced recently from 10 average megawatts ("aMW") (approximately 30 megawatts ("MW") nameplate rating for wind) to 100 kW for wind and solar should remain low, as IPC proposes. It also should be reduced for other types of QFs, notably hydro, because

hydroelectric projects are least amenable to generic surrogates. If the IPC proposal to use separate generic standard offers for the different technologies is implemented, it could be appropriate to increase the ceiling somewhat from the current 100 kW if it is found that transaction costs of individualized rate negotiations for small projects are too onerous.

4. Regarding the capacity element of avoided cost, I support IPC's proposal to switch from a combined cycle to a simple cycle peaking unit. As I shall explain later in my testimony, both theory and nearly universal practice in the Regional Transmission Organization ("RTO") markets that have capacity products is to base capacity values on the net capacity cost of a peaker.

5. Regarding the energy component of avoided cost, I concur with IPC that the "letter of the law" of PURPA is that avoided costs are the costs that the utility avoids from on-system production or power purchases and does not extend to paying QFs the incremental revenues that might be earned from selling the QF power or other power displaced by the QF into interchange markets. PURPA requirements aside, it is poor public policy for IPC to be required to enter into long-term obligations to pay QFs the expected market price for power it incrementally will have

to sell off system. I recognize that there may be circumstances when IPC can sell QF power in interchange markets for more than they will pay the QF under IPC's proposal. A developer who believes it will be under-paid as a QF can either develop a project elsewhere or build it in Idaho but not request a QF contract, instead selling into the commercial market. A further alternative is to sell it to IPC under its existing non-firm QF contract that pays the project the net-back price of power delivered at mid-Columbia.

6. I also support IPC's proposal to reduce the required length of QF contracts. Even if it were deemed appropriate to make projects "bankable" there is no reason to extend contracts beyond 10 years. Moreover, there is no reason why Idaho utilities' customers should take on risks that properly belong to the QF developers. In my opinion, IPC is if anything being overly generous in terms of the length of contract that it is proposing. The contract term it is offering is longer than is available in exempt markets and exceeds the length of time that Idaho utilities can hedge contract obligations to buy power that must be disposed of in interchange markets. The need for shortened contracts also relates to the market risks that customers are being required to take on. If, as IPC proposes, customers are largely insulated from risks

relating to on-selling QF power into interchange markets, contract length is somewhat less sensitive.

7. The Idaho utilities currently differentiate between fueled and non-fueled QFs with the former receiving prices that change year-by-year based on actual gas prices rather than prices that were forecast at the time of signing. Such an arrangement benefits both QF developers and the utilities' customers since it reasonably hedges the prices paid by the utilities and locks in margins above fuel costs for the developers. This contract form should be continued, as I understand IPC intends. The benefits to customers from this form of contract are not different merely because the QF is non-fueled. While IPC is not proposing to extend this type of contract to non-fueled QFs, I have recommended earlier in this testimony that the Commission seriously consider this or other changes to the form of non-fueled QF contracts to reduce the risks borne by customers.

8. IPC is not proposing a market alternative to administratively set avoided costs. Given its excess energy situation, using an RFP to procure least cost QF and other capacity does not seem to be a current option, since the appropriate quantity in such an auction would be zero. The other market option, passing market prices from nearby visible competitive markets through to

QFs in lieu of paying administratively determined avoided cost rates, may or may not be consistent with PURPA depending on specific facts concerning market access that I have not examined. I nevertheless recommend to the Idaho Commission that it examine the possible use of market mechanisms as an alternative to administratively set avoided costs now or at such later time as the facts warrant.

III. PURPA PURPOSES AND HISTORY

Q. What is the origin of the requirement to purchase power from QFs?

A. The requirement originates in PURPA. PURPA was one of the energy policy acts passed in the latter half of the 1970s to implement the energy efficiency and domestic energy supply goals of the Carter administration's Project Independence. In response to the oil embargos that disrupted oil supplies to the U.S. and caused both shortages and several-fold increases in prices, the government promulgated policies designed to reduce (with the goal of total elimination) dependence on imported oil. These policies included increasing domestic oil and gas production, promoting the use of renewable and other domestically produced energy, more efficient energy conversion (e.g., in producing electricity), and more efficient consumption of energy, among other things.

Section 210 of PURPA is a relatively brief portion of the bill that mandated arrangements under which electric utilities would sell electricity to, and buy electricity from, qualifying cogeneration and small power production facilities. Section 210 tasked FERC to devise rules that "it determines necessary to encourage cogeneration and small power production and to encourage geothermal facilities of not more than 80 megawatts capacity."[1]

Q. What guidance does the Act give FERC concerning its implementation regulations?

A. The guidance is brief and mostly non-specific. There are a few statements, however, that constrain and direct FERC's implementation.

The portion of Section 210 dealing with purchases required rules that "shall include provisions respecting minimum reliability of qualifying cogeneration facilities and small power production facilities (including reliability of such facilities during emergencies). . . ." The portion dealing with rules concerning rates to be paid to such facilities by electric utilities:

[1] FERC's implementation treated the cut-off for small power facilities as a maximum of 80 MW. However, this misread the plain language of the Act, a careful reading of which shows that Congress applied the 80 MW cut off solely to geothermal. A later passage in Section 210 dealing with exempting such facilities from being regulated as public utilities made such exemption available to geothermal plants of less than 80 MW and other small power facilities of less than 30 MW. As a classic example of bootstrapping, FERC later acknowledged this, but continued to apply an 80 MW limit on the grounds that this always had been its policy.

> shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase:
>
> (1) Shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
>
> (2) Shall not discriminate against qualifying cogenerators or qualifying small power producers.
>
> No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

The "incremental cost of alternative electric energy" was subsequently defined:

> For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would produce or purchase from another source.

Q. Did the Act show Congressional intent to subsidize QFs?

A. No. It cannot be over-emphasized that the intent of PURPA Section 210 was to eliminate discrimination against QFs, not to subsidize them. PURPA also was intended to shield QFs from being regulated like public utilities. This shielding was perceived to eliminate cost of service ratemaking as a full or partial basis for pricing QF power. This eliminated the customary method for assuring that prices paid were just and reasonable. To avoid subsidization of QFs by utility ratepayers, the upper limit on payments to QFs was set at the costs that the utility would avoid as a result of receiving power from the QFs. In implementing Section 210, FERC concluded that avoided cost should be not only the ceiling but also the floor for avoided cost computation.

Q. What pricing terms are available to QFs under Section 210?

A. The Act contemplates two classes of pricing terms. First, the utility could pay the QF its avoided cost as actually avoided at the time that the QF delivered power. This was the only pricing method available for QFs selling "as available" non-firm power. The Act also contemplates the possibility of contracts that fix prices or pricing formulae at the time of signing as an alternative to the payment of actual avoided costs at the time of power delivery. Congress expressly found that divergence between contractual prices and actual avoided costs would not in and of itself violate the Act. It is unclear whether, as a matter of law (as distinct from FERC or state regulatory implementation) that the option to set prices at the time that the contract was signed had to be offered. However, if it was, the QF had the unilateral right to select between this form of contract and being paid avoided costs calculated at the time of delivery.

Q. Does the Act require tariff-like standard avoided cost rates for purchase contracts?

A. Yes, but only for very small projects. The utility is required to have a standard rate for sellers of less than 100 kW and may, but need not, have a standard rate for larger projects. These standard rates are expressly permitted to vary by type of projects.

Q. What do FERC's implementing regulations say about these types of contractual arrangements?

A. The pertinent part of the regulations ((§294.304(c)(3)(d)) distinguishes between as available power sales and sales pursuant to a term contract. In the former case, prices are avoided cost at the time of delivery. In the latter case, they can be set at the time of contracting. FERC recognizes expressly that such rates may differ, even substantially, from actual avoided costs at the time of delivery. FERC gives the QF developer the unilateral right to select between the two contract forms. However, the regulations do not expressly require that the utility offer a long-term contract with fixed prices at all, so this unilateral right is contingent on the alternative being offered.[2] All of this parallels the requirements of the Act.

What is not clear (and I pretend no legal analysis of the points) is whether a contract for non-dispatchable, intermittent energy such as wind is "as available" and hence is only entitled to a rate determined at the time of delivery.[3] Assuming that such a QF is not deemed "as available" and hence is entitled to a rate determined at the time of contracting, it is similarly unclear whether this can be a formula rate (e.g., one that is indexed to vary with, for example, gas prices or inflation) or if the utility must offer a fixed schedule of rates for the term of the contract. Relevant to this point, nothing in PURPA or the regulations specifies a required length of contracts. Hence, even if the QF is deemed eligible for a fixed rate for the term of the contract, the utility can offer only a relatively short-term contract.

Q. Does FERC allow non-conforming contracts?

A. Yes. FERC gives very wide latitude to QFs and utilities to agree to whatever form of contract is mutually acceptable. It expressly permits such contracts to yield

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[2] In RM88-06 (1988), FERC clarified that the prices offered at signing could be formula rates, not fixed prices.

[3] The specific language in the regulations distinguishes between as-available power and power from QFs able "to provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term."

rates that are below full avoided cost, reasoning that the QF might agree to a lower price in return for some valuable non-price contract provision to which it was not expressly entitled under PURPA. Conversely, such negotiated contacts cannot lawfully result in prices that exceed the utility's avoided costs as calculated or incurred, whichever is pertinent. Thus, while PURPA and FERC's implementation of it speak of encouraging cogeneration and small power, such encouragement is limited by a no subsidy provision that does not allow rates to be set at a level higher than the utilities' incremental cost since such a rate would not be just and reasonable to consumers.

Q. Did FERC's 1980 PURPA implementation give further guidance to the states in formulating more specific implementation of Section 210?

A. Yes. The regulations specified data that the utility must provide to its state regulator(s) and directed that this data should be taken into account in determining avoided costs The regulations further said that rates should be consistent with this data. 18 C.F.R § 292.304(e) states that in setting avoided costs, "the following factors shall, to the extent practicable, be taken into account: . . ."

2. The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

   i. The ability of the utility to dispatch the qualifying facility;

   ii. The expected or demonstrated reliability of the qualifying facility;

   iii. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

   iv. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

   v. The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

   vi. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

   vii. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

> 3. The relationship of the availability of energy or capacity from the qualifying facility as derived in [the methodology based on i through vii] to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
>
> 4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

Q. Did state implementations of Section 210 occur soon after FERC issued its regulations in February 1980?

A. No. Most states were somewhat slow to provide the detailed rules needed to implement Section 210. This was in part due to litigation concerning the FERC regulations, focused primarily on FERC's interpretation that PURPA required payment of full avoided cost rather than some form of benefit sharing for new QFs. Ultimately, in 1982, the U.S. Supreme Court ruled that FERC's actions were within its discretionary authority. While some states had moved quickly, others only began the process of implementation at this time.

State implementation of PURPA occurred primarily between 1982, when litigation concerning FERC's implementation was resolved, and the mid-1980s. This was an era when many state commissions were distrustful of utilities' resource decisions as a result of overbuilding and cost overruns for plants coming on-line during the period. Some such commissions welcomed QFs in preference to continued reliance on utilities building and owning all new facilities.

Q. Recognizing that you plan to discuss how PURPA has been implemented in some detail later in your testimony, can you provide an overview of this initial implementation?

A. In all cases, state implementation was based on administratively determined costs. By administratively determined I mean that costs were determined by methodologies or formulae determined or approved by regulators or legislative action rather than by observation of market outcomes.[4] In the early 1980s there were no competitive power markets with visible prices. Almost universally, utilities were vertically integrated and built their own generation, so that there was little opportunity to observe long-term market prices. There were no independent power producers as that term came to be used in

[4] Short-term contracts for as available power are an exception to this generalization since such power was, per requirement of the Act, paid the utilities actual avoided cost at the time of delivery. Even this actual price was determined by methods created through regulation since there was little if any price transparency.

the 1990s. Hence, state implementation of PURPA inherently involved study-based, rather than market-based, estimates of avoided costs.

The state-by-state implementation resulted in a wide range of administrative avoided cost calculation methods, as I shall discuss later. Several of them certainly did not take into account the factors that FERC had said should be taken into account to the extent practicable and may even have been facially inconsistent with the avoided cost definition contained in the statute and adopted in the regulations.

Q. Can you overview the main varieties of avoided costs methods that the states adopted?

A. Several methods were adopted, for which the two main archetypes were a proxy unit, whose capacity and energy costs were used to define avoided costs, and the IRP or Differential Cost method, which measured avoided costs as the costs avoided as a result of contracting with the specific QF in question. In addition, as a matter of law, each state had a posted schedule of prices available to units of no more than 100 kW, a limit extended higher and even eliminated in some states.

Of the two methodologies, only the IRP method was fully consistent with the definition of avoided costs contained in the Act. However, this distinction did not appear to be important at the time and, in the minds of many, did not warrant the additional complexity and transactions cost of the IRP method.

Q. Why did the methodologies appear to yield similar results?

A. At the time of initial state implementation, the differences between the two types of methodologies were not inherently large due to the nature of the QFs. Most QFs were cogeneration units based on standard fossil power plant designs, geothermal power, biomass (particularly wood waste in timbering areas) and municipal solid waste. All of these technologies had performance characteristics that were reasonably similar to the conventional utility plants used as proxy units. While some wind units were built in the 1980s, the technology of the day did not extend to large turbines or wind farms.[5]

Q. Was PURPA as implemented successful?

A. It certainly was successful in causing large amounts of QF capacity to be built. However, as noted previously, creating QFs was not the intent of the Act. Rather, the intent was merely to eliminate discrimination against them as a barrier to their construction.

[5] The notable exception to this generalization was California. Many thousands of small wind turbines were built in three wind farm areas, at least partly as a result of non-PURPA state subsidies.

The most obvious negative impact of PURPA was that in some states contract rates significantly exceeded the actual avoided costs when the power was delivered. This arose in part because some state implementations required utilities to offer avoided cost contracts of long duration that also were sometimes front-loaded. These contracts also contained pre-set prices. Since the Act and FERC regulations provided no evident basis for limiting the amount of QF power the utilities were required to buy, these contracts were not, in at least some states, limited to the amount of power the utilities needed.[6]

A primary reason why prices were far above avoided costs was that fossil fuel prices, especially the price of natural gas, fell substantially soon after most state implementations. Gas was the primary fuel used by cogenerators. Hence, a contract rate based on a high gas price forecast not only exceeded avoided cost, it also substantially exceeded the cogenerators' costs. The combination of a too-high rate, long contract durations and no quantity limits, led to unexpected amounts of QF development, primarily in the states with such long-term fixed offers. In all likelihood, the "gold rush" rapidity

[6] QF development was very uneven across the country. One of the reasons that some regions had little QF activity was that the early to mid-1080s was a period of substantial excess capacity in much of the country. This sometimes was reflected in lower, "energy-only" avoided cost rates.

of entry was compounded by the fear on the part of developers that a too-good deal would not long persist.

Q. Can you provide examples of the extent to which these high prices created a glut of high priced QF capacity?

A. The two leading examples of the adverse consequences of long-term fixed price offers without quantity limits were California and New York. California established Standard Offers 2 and 4 (September 1983) that provided for fixed avoided cost rates, no limit to the size of the unit built (FERC had required Standard Offers for any unit below 100 kW) and allowed the QF to opt for levelization of payments. The offers were suspended in April 1985 when it became apparent that there was neither a need for the quantity of capacity (16,000 MW under contract or in the contracting process in the mid-1980s) nor the excess cost for the energy, estimated by Southern California Edison and Pacific Gas & Electric, the two largest utilities, to be $1.15 billion per year by 1990.[7]

Earlier the New York state legislature had passed a law requiring that the state's utilities enter into long-term contracts with QFs. The New York Public Service

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[7] See Frank Graves et al, *PURPA: Making the Sequel better Than the Original*, (prepared for The Edison Electric Institute), The Brattle Group (December 2006) on-line at: http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/purpa.pdf, at p. 16.

Commission was to set the rates but was constrained to set them no lower than 6 cents per kWh, well above the then-current avoided costs of utilities in New York.[8]

This was argued to be acceptable because it had encouraged significant quantities of QFs into the state and had had little impact on the consumer price of electricity. New York utilities argued (unsuccessfully) that the 6 cent number was well in excess of their avoided cost with Consolidated Edison stating that in 1986 their avoided cost was only 3 cents and Orange and Rockland arguing it was 3.4 cents. Orange and Rockland went further to state that they did not anticipate their avoided cost to reach 6 cents until 1995.[9]

The cost of excess QF power bought under the 6 cent rule became manifest when New York restructured the electricity industry, requiring generation divestiture and retail access, among other things. Niagara Mohawk, a mid-size utility, obtained regulatory permission to enter into negotiations to terminate or modify its QF obligations in order to quantify its excess costs that would become

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[8] FERC later opined that New York may have relied on a statement that it had made in the preamble to its regulations to the effect that states could require rates above avoided costs, notwithstanding PURPA. However, since such rates were facially inconsistent with the express language of the statute, the legitimacy of such rates could not rely on PURPA. Nevertheless, New York treated the 6 cent program as PURPA related, requiring that its utilities accept all QF power offered to them and pay this rate.

[9] *Ibid* at page 15.

stranded by the change in industry structure. It succeeded in cancelling 14 of its 27 QF contracts at a cash cost of $3.9 billion plus 23 percent of Niagara Mohawk equity.

Q. Was dissatisfaction with the results of PURPA implementation limited to these two states?

A. No. Other states also had considerable excesses of PURPA power. Many such states either suspended or diminished their PURPA offers. Others began to ration QFs, along with non-QF new capacity offers by creating quantity-limited procurements, with the lowest, quality-adjusted offers being accepted and all others rejected. Conversely, QF developers in some other states complained that they were not being offered payments for capacity. This dissatisfaction in both camps led to the next chapter in the PURPA saga, the Congressional hearings of 1986 and the FERC Notices of Proposed Rulemaking ("NOPRs") of 1988.

The RM-88 NOPRs

Q. What was the origin and subject of the NOPRs?

A. The substantial unhappiness with the results of PURPA implementation led to hearings in both houses of Congress in June of 1986. FERC responded by holding regional conferences in the spring of 1987 at which various parties testified concerning changes in FERC's regulations implementing Section 210 that would eliminate undesirable parts of state implementations. After the hearings were conducted, FERC issued three interrelated NOPRs[10] in the spring of 1988. These concerned: (a) the treatment of independent power producers, (b) the use of structured procurements to, among other things, comply with PURPA (the Bidding NOPR), and (c) changes in the existing PURPA avoided cost regulations (the Avoided Cost NOPR). The latter two are relevant to the issues in this proceeding.[11]

Q. Were the regulations proposed in these NOPRs adopted?

A. No. The NOPRs were very controversial at the time. The controversy was not primarily about the changes they proposed in regulations concerning avoided cost pricing, but in the way in which the NOPRs proposed to restructure the electricity industry. Much of what the NOPRs proposed has since occurred. Fundamentally, the NOPRs called for open transmission access, mandated but did not require competitive bidding for contracts for all new generation including utility provided generation that would then not be subject to cost of service regulation, and

[10] FERC uses NOPRs as a mechanism for eliciting comments from interested parties concerning proposed changes in regulations. Usually, they contain a long discussion of the issue being addressed and a draft of the proposed new regulations. While a NOPR is not itself a regulation, it generally contains substantial information about how the Commission would react to particular fact circumstances.

[11] The Independent Power Producer NOPR proposed streamlining regulation of a proposed new type of generators that would not be subject to cost of service price regulation. This presaged the creation of Exempt Wholesale Generators in the Energy Policy Act of 1992, but has no direct relevance to the PURPA story.

provisions to police self-dealing in utilities' selection between affiliated and unaffiliated generation proposals.

Among those opposing the NOPRs were National Association of Regulatory Utility Commissioners and one of the FERC Commissioners, who wrote a scathing attack on the legality of the proposed changes in regulations insofar as their effect was to restructure the industry. The proposed regulations were quietly abandoned and FERC moved on to a more gradual change in policy, beginning with Order 888 on open access in 1998 and with the further changes authorized or enabled by the Energy Policy Acts of 1992 and 2005.

Q. If the NOPRs did not change FERC's regulations, why are they worth discussing?

A. Notwithstanding the fate of the NOPRs, they provide a useful summary of problems that arose in the implementation of PURPA and important information about FERC's interpretation of its own regulations that, in relevant part, are little changed today.

The Avoided Cost NOPR, RM88-6

Q. Did the NOPR recount comments received and lessons learned in the Congressional hearings and its own regional conferences?

A. Yes. The NOPR recounts the types of dissatisfaction with the way that states had implemented the avoided cost standard in Section 210. Overall, FERC characterized the comments as calling for moderate changes and being focused primarily on the treatment of capacity. FERC's description of criticisms of the implementation of the portion of Section 210 regarding QF purchases by utilities were organized into the following topics:

1. Inappropriate Methods for Determining Avoided Costs.

a. Quantitative Limits on Capacity Needs. FERC characterized this as the most common complaint. The 1980s were a period of substantial excess capacity in much of the U.S., but utilities nonetheless were required to buy energy and capacity from QFs, often based on avoided cost methods that assumed a need for capacity. Conversely, QF developers complained that many states' implementations gave no capacity credits. The most common specific complaint arose from a lack of quantity limits in the requirement to sign contracts or in the amount of QF capacity that would receive payments for capacity.[12] FERC pointed to standard offers, extended far past the 100 kW statutory requirement as one source of this problem, but commented that the "committed capacity"

[12] As a lead example, FERC cited comments by Pennsylvania Power and Light. Its state commission disallowed the entirety of its Susquehanna 2 nuclear plant from rate base as not used and useful because it was excess to the company's capacity requirements but then required the company to contract for 500 MW of QFs.

approach[13] and other avoided cost methods also could lead to unlimited capacity commitments.

b. Failure to Take into Account Qualitative Characteristics. In its 1980 regulations implementing PURPA Section 210, FERC had listed several qualitative factors that must be considered but need not be taken into account in state implementations. Comments criticized many of the methods used for not differentiating between the characteristics of QFs and the plant used to set avoided cost, using a proxy unit that is not consistent with the utility's needs to set avoided costs, and not differentiating among QFs in terms of characteristics such as dispatchability.

c. Problems When QF Capacity Offered Exceeds Utility Needs. Even reasonably calculated avoided costs can elicit more capacity than is needed under some circumstances. This especially is true if all capacity receives capacity payments. FERC also noted that some states that did ration capacity payments used methods that may not be efficient, such as first come, first serve.

d. Wholesale Sources. Proxy unit methods inherently assume that avoided cost relates to the cost of power from the proxy unit, whereas for many

[13] The committed capacity method used the costs of either the last unit built by the utility or the costs of the next unit proposed to be built by the utility as the proxy unit for calculating avoided costs.

utilities, the lowest cost alternative was purchases from other utilities. Further, some commenters indicated that their state commissions did not understand that avoided purchases could ever qualify for use in avoided cost calculations.

2. Fixed Price Contracts. Some commenters complained that fixed price, must take QF contracts prevented the utility from buying substantially cheaper economy energy as an alternative. Others noted that at times they had to back down low variable cost baseload units to make room for more expensive QF power. Still others asked for guidance concerning the use of fixed prices in long term contracts.

3. Rates Exceeding Avoided Costs. FERC noted that some states had interpreted part of FERC's regulations as allowing states to set PURPA rates above avoided costs. The New York 6 cent minimum price, which the New York State Department of Public Service ("NYPSC") Chair stated was above any of the state's utilities' avoided cost, was said to be predicated on this belief. FERC clarified that its intent when it earlier stated that rates above avoided cost were permissible had been to point out that, *outside* of PURPA, states could mandate purchases at above avoided costs. PURPA rates, however, could not exceed avoided cost.

4. <u>Multistate Utilities</u>. Utilities that were jurisdictional to more than one state complained that different state implementations led to different avoided costs. This arose both from adoption of different methodologies and from basing avoided costs on the avoided costs of the subsidiary that provided service in that state rather than on the system as a whole.

Q. What are the major points made by FERC in the avoided cost NOPR that you believe warrant emphasis?

A. In this NOPR, FERC clarified or emphasized several matters that still bear on the setting of avoided costs. One point made was that PURPA was not intended to subsidize QFs, whatever their merits: "It should be emphasized that the avoided cost standard dictates that QFs should be paid consistent with, not their social value, but the costs of displaced sources of power to utilities. The criteria for qualification as a QF must carry the burden of assuring that the QF's mode of generation is socially desirable. [p.30]"

The Commission also stated that problems were arising from avoided cost methodologies that imputed value to the QF that, in fact, were phantom:

> Inaccurate calculations of avoided capacity cost appear to result in part from a lack of attention to the relationship between the characteristics of the QFs involved and the quality,

> quantity, or source of the capacity avoided. For utilities to use QF power instead of building new plants or purchasing power, it is necessary for the qualitative characteristics of QFs and utilities' plans to at least roughly coincide. [p.35]

Several portions of the NOPR emphasize that the capacity payments to be made to a QF depend critically on whether the existence of the QF allows capacity to be avoided. For example, "Under the Commission's current regulations, capacity payments need to be made when, and only when the purchase or construction of capacity will be avoided by the purchasing electric utility as a result of its purchase of QF power [p. 6]." Still more emphatically:

> Section 292.204(c) of the current regulations has been read as allowing open-ended standard offers to all QFs. It is clear, however, that the avoided cost standard requires that QFs be paid for only the capacity cost that a utility avoids because of the presence of QFs . . . . To address this problem, the Commission proposes to amend . . . its regulations to assure that [under] such standard offers . . . capacity payments would not be available once the purchasing utility's capacity needs have been satisfied. [p. 48].

FERC also considered the issue of the availability of standard rates as opposed to QF-specific calculations of avoided cost. It stated that, based on experience, it proposed to raise the threshold from the statutory 100 kW to a project size of 1 MW.

In a section entitled "avoided energy costs," FERC endorsed time-based differentiation of avoided energy payments, recognizing that energy costs differ by season and time of day.

Q. Did the Avoided Cost NOPR discuss the problem of long-term contracts with fixed prices?

A. Yes. An entire section of the Order (pp. 55-67) dealt with problems arising from fixed price contacts. It noted that QF revenue certainty rendered via contract provisions shifted risks from the QF to the purchasing utility or its ratepayers. It also noted that fixed rates could reduce transaction costs, which could be important for small QFs. It made clear that its use of the term "fixed price" incorporated a variety of rate types for which the only common feature was that they were set based on provisions contained in the contract:

> For purposes of this proposed rule, the term "fixed-Price contract" refers to any legally enforceable obligation wherein the rates for purchases by a utility are established in advance of the time of purchase. The fixed price may be a single, uniform rate per kilowatt or kilowatt-hour for all power, including a fixed formula rate, or a complex schedule of time-differentiated rates and other payments. The contract's term may range from decades to months. [p.56]

From this description, and in particular the inclusion of formula rates, it is reasonable to interpret that the Commission was of the view that the right of a QF unilaterally to select a contract based on avoided costs determined at the time of the contract did not extend to the right to insist on a predetermined schedule of prices for the duration of the contract.

The Commission noted that inefficiencies arose whenever rates deviated from avoided costs, since the utility would be paying too much or too little. Further, when it was paying too much, this could mean that QF power was being purchased and produced in lieu of lower cost, more efficient power. It noted in particular the rigidity arising from non-dispatchability:

> Most of the problems with efficiency associated with long term fixed-price contracts flow from the rigidities such contracts impose on price and quantity of electricity. These problems can be ameliorated by relaxing restriction on price or quantity, or by shortening the contract period. Quantity flexibility implies QF dispatchability. If the utility is unable to "turn the QF off" it may be unable to take advantage of economy energy, or it may have to back down its more efficient plants to buy higher priced QF energy. If the utility cannot "turn the QF on" it may not be able to take advantage of the QF's capacity when it is most needed during peak demand or a system emergency. [pp.61-62]
>
> The Commission proposes to amend its regulations in order to allow for greater pricing flexibility. Pricing flexibility may take several different forms. For

instance a contract could provide QFs with a price floor applicable to all the power supplied to the utility, but still provide for higher variable unit prices reflecting daily or seasonal periods. The price floor would provide the revenue stream necessary for the QF to secure financial support while the price variability would induce the QF to maximize deliveries in peak-load periods when the utility values additional supplies most. Of course, the price floor should not exceed the minimum value of the utility's avoided cost. Similarly, a contract could provide for a two part price - a fixed payment for capacity and an energy price for power delivered. The QF would be assured a minimum revenue stream based on the value of its capacity. The variable energy component would allow the utility to dispatch the QF capacity only when it was economic. Whatever the pattern of contract payments, rates for purchases from QFs should always reflect how well the characteristics of the supplier's power match the purchasing utility's need . . . .

To avoid problems such as those associated with take-or-pay contacts in the natural gas industry,[14] the Commission wishes to stress the danger of including forecasted fuel costs in the fixed rate structure of long-term contracts, especially in combination with the specification of minimum purchases quantities. The Commission also encourages the use of time-of-day and

[14] Following partial decontrol of wellhead natural gas prices, uncontrolled incremental prices escalated rapidly. Many natural gas utilities signed take or pay contracts at very high prices. When decontrol became complete, eliminating low prices for non-incremental gas and expanded supply created a glut of gas, prices fell very substantially. This created a regulatory problem: either contract costs far in excess of actual costs would have to be passed through in rates or the excess costs would be "trapped" in the utility, leading in some cases to bankruptcy.

seasonal rates in flexible pricing structures for long-term contracts. [pp.65-66.]

Q. Did the Commission express surprise at the extent of the problems identified concerning the scale of QF power brought about by long term contracts at fixed prices?

A. Yes. Elsewhere in the NOPR, the Commission commented that the risk that QFs would offer more capacity than the utility could use had not been anticipated at the time its regulations were written, but had become manifest as a result of the rapid growth in QF power. It noted that in its 1980 Order it had forecasted 2,636 MW of QF power by 1985, whereas the amount actually installed (i.e., not including contracts requested or contracts signed with facilities not yet in production) was 12,120 MW.

Q. Did FERC also address revenue shaping for long term contracts?

A. Yes. One issue concerning long-term contracts discussed by the Commission was the front-end loading of revenues. The Commission expressed concerns about intergenerational equity arising from front-end loading. It also voiced a concern that, having received above market prices in the early years, the supplier would walk away from its contractual responsibility which could turn out to be delivering power at a loss in the later years.

Q. Did the Commission provide advice to states concerning how to avoid attracting unneeded capacity?

A. Yes. The Commission acknowledged the difficulty of administratively setting avoided cost rates at the proper level, such that mistakes were not always avoidable. It suggested that states should monitor whether their avoided cost rates were attracting unneeded QFs and, if so, consider lowering them. Intriguingly, despite language in PURPA and in the Commission's regulations that seemed to require utilities to buy power from QFs in the amounts offered, it suggested that a state that had set rates that attracted too much power could suspend the rate pending its recalculation:[15]

> If, in response to such a standard rate or standard offer, QFs offer much more capacity than the utility needs, a prospective adjustment to the rate should be considered for contracts that have not yet been entered into. If the excess amount of offered capacity is large, then the state regulatory authority or non-regulated electric utility may want to re-examine its method for determining avoided capacity costs to see if some efficient alternatives available to the utility were not considered. The Commission believes that if QFs offer capacity in amounts greatly exceeding the utility's capacity needs, then the rate for purchase of that capacity was probably not set in reference to the cost of the utility's most efficient

[15] As I noted earlier, this suspension of a standard offer is precisely what California had done to choke off its massive surplus of QF offers.

> alternative. A rate that does not reflect the cost of the utility's most efficient alternative source of capacity is excessive, and should be adjusted downward. . . .
>
> Moreover, even a properly calculated standard offer will not remain appropriate indefinitely. The alternative upon which a rate is figured comprises a certain block of capacity. If this block is fully satisfied, a change in the standard offer may be necessary.
>
> The Commission recognizes the difficulty of administratively setting avoided cost rates that induce QFs to supply capacity in amounts that exactly match a utility's needs. Obviously, the signing of contracts with QFs cannot and should not be postponed until a rate has been set that successfully matches the amount of QF power with the capacity needed by the purchasing utility. . . . Rather, in the event that it becomes clear that a rate is eliciting more QF power than the utility needs, the state regulatory authorities or non-regulated electric utility could suspend the rate. [pp. 41-42.]

Q. Did the Commission express optimism that the changes it was proposing and the advice it was giving in the Avoided Cost NOPR would fix the identified problems?

A. No. Frustration with the difficulty of getting administratively determined avoided costs to achieve the purposes of PURPA Section 210 led the Commission to propose bidding as an alternative to administratively set offers:

> Admittedly, administratively calculated avoided cost is unlikely to successfully result in an equilibrium price. The Commission believes that bidding is an alternative that promises efficiency in both determining avoided cost rates and assigning avoided cost payments among QFs.

The thinking behind the Commission's espousal of bidding, and in particular the use of bidding as a way to evade the apparent inability to refuse QF power, is buried in a long footnote in the Avoided Cost NOPR:

> The Commission has tentatively concluded that purchases from other QFs fall within the meaning of "another source" under the section 210(d) definition of "incremental cost of alternative energy. . . ." If a utility does not purchase from one particular QF, it certainly has the option of purchasing power from other QFs . . . . Obviously, if a utility purchases power from a QF at a price that is higher than a rate for comparable power available from another source, whether it is another utility or another QF, the purchasing utility's customer rates would be higher than they would have been had the purchase not been made and the purchasing utility had purchased from that other source. [pp. 35-36]

The Bidding NOPR, RM88-05

Q. What was the purpose of the bidding NOPR?

A. The bidding NOPR proposed draft rules for using bidding to set utilities' avoided costs for use in purchasing from QFs. As stated in the introduction to the NOPR:

> The Federal Energy Regulatory Commission (Commission) proposed to adopt regulations that would authorize state regulatory authorities and nonregulated electric utilities to implement bidding procedures as a means of establishing rates for power purchases from qualifying facilities (QFs) under section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). A bidding program is a formally organized market to acquire incremental supplies of electricity. . . . This proposed rule sanctions the use of bidding as a procedure for purchasing electricity for purchasing electricity from QFs.

The Commission determined that bidding could eliminate errors and controversy in administratively determined avoided costs. In particularly, it noted that some state regulators ignored whole classes of alternatives, relying on a single proxy unit that may not be the utility's lowest cost alternative which, particularly in times of overcapacity, often is a purchase.

The Commission noted that states and utilities were only just beginning to experiment with bidding[16] and that it was therefore reluctant to be too proscriptive about how procurements should be organized. States were free to adopt bidding for some, all, or none of the utilities' requirements. Moreover, while FERC uses the term "bidding" to refer to the procurement methods covered by this NOPR,

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[16] It states (page 15) that Maine, Massachusetts, and California had promulgated bidding rules and that Texas had a related form of procurement. Bidding was said to be under development or at least consideration in 14 other states, one of which was Idaho.

it stated that a wide variety of approaches would qualify as bidding.

Q. What benefits were seen to arise from using bidding as a method of determining avoided costs?

A. While using price discovery in market procurements to set avoided cost was one goal of the Commission's bidding proposal, it was not the only and perhaps not even the main reason for advocating it. The Commission stated flatly that "the purpose of bidding is to determine which suppliers will receive avoided capacity payments." Implicit in that statement is the presumption that a state that adopted bidding would procure all of the utilities' capacity needs through the bidding process, notwithstanding its statements elsewhere that bidding could be used to meet only part of the requirements. Non-QF projects that were not selected, including projects sponsored by the utilities themselves, would have no right to any revenues and presumably would not receive siting approval.

Q. Did adopting bidding mean that states could avoid the utilities' open-ended obligation to buy QF power at their avoided costs?

A. No. The Commission recognized that PURPA Section 210 did not limit the requirement to buy QF power to the amount that the utility needed for reliability purposes. However, it reasoned that the PURPA's "must buy" requirement did not extend to paying capacity payments to QFs that were unneeded and not selected as being economic in the bidding procedure. Hence, while the utility still would have to pay an administratively determined energy payment to QFs that did not have accepted bids, the QFs would not be entitled to capacity payments.

Left unsaid was the expectation that few QFs would be built if they did not receive capacity payments. At the time of the NOPR, avoided energy would typically be from coal or gas-fired capacity (owned or purchased) and priced at relatively low marginal costs. This would be true all of the time if the administratively determined energy price for QFs not selected in response to the RFP was based on a proxy unit, and much of the time even if IRP-type methods were used. Hence, most QFs would earn quite little from these avoided energy-only payments. By limiting the amount of capacity/energy production capability purchased via bidding to the amount that the utility needed and limiting the right to earn avoided capacity cost to the winning bidders, the inefficiency otherwise inherent in the statutory obligation to purchase unlimited QF energy would be finessed.[17]

Q. Did the Commission provide guidance about who should be allowed to participate in bidding?

A. The Commission expressed a preference that bidding would be "all source" bidding, with QF, Independent Power Producer, and utility projects all competing simultaneously. It reasoned that only an all-source procurement could ensure that the least cost capacity and energy was being procured. Having stated this preference, the Commission then proposed that all sources could be deemed to have been taken into account in a bidding procurement even if they could not participate directly. One of several ideas that it floated was that a "benchmark" avoided cost could be established based on the utility's IRP and the procurement would then be for resources that would replace portions of it.

Q. Was bidding proposed to select winners solely on the basis of price?

A. No. The NOPR stated that non-price attributes could and should be taken into account in the "scoring"

[17] "PURPA imposes an absolute duty upon a utility to offer to purchase electric energy from QFs at rates that do not exceed the 'cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source. The Commission has interpreted electric energy to include capacity *when capacity is avoided by the utility as a result of its purchase from the QF.*" [Emphasis added; p. 37.]

used to select winning bids. It left it to the states and (where state regulators so-delegated) the utilities to develop appropriate procedures.

Q. Was this proposal a radical change when viewed from the prospective of 1988?

A. Yes, it was. The NOPR pre-dated the creation of the class of Exempt Wholesale Generators by four years and the earliest state-level restructuring of utilities by about eight years. I noted earlier that the three NOPRs proposed by the Commission in March of 1988 were never converted into regulations. The bidding NOPR is likely the primary reason for the fierceness of opposition. The bidding NOPR proposed to replace cost of service regulation by market based prices established in auctions. This would eliminate cost-based regulation of new (and ultimately all) utility-owned generation that was primarily a province of state commissions. The dissenting Commissioner charged that the majority was seeking to unilaterally restructure the industry based on a "Genco/Disco" model of utilities, where the GENCO was not price regulated, and competed with similarly unregulated IPPs.

Q. Notwithstanding that the NOPRs were not adopted, were the concepts contained therein subsequently put to use?

A. Yes. While this NOPR may well have been a "bridge too far" in 1988, many of the core concepts in it, including those that were considered most radical, were adopted subsequently. The "Genco/Disco" model of industry structure was already under active discussion. The model was implemented two years later in the United Kingdom and became the preferred template for all of the European Community under regulations enacted by the Community in the early 1990s. The U.S. Energy Policy Act of 1992 created Exempt Wholesale Generators, independent power producers allowed to compete to sell at wholesale to utilities without the cost of service and other utility regulations to which they previously would have been subject.

Several states adopted competitive bidding as the primary means of procurement shortly after the NOPR. Within a decade, the "Genco/Disco" model was adopted for more than half the load-serving utilities in the country.

The Energy Policy Acts of 1992 and 2005

Q. You mentioned the Energy Policy Act of 1992. What did that Act do that relates to your testimony?

A. The Act created a new class of generators, called Exempt Wholesale Generators ("EWGs") who, like QFs were exempt from utility regulation but, unlike QFs, were not limited in size or fuel type. Also unlike QFs, they had no right to "put" contracts to utilities. Many saw the evolution of privately sponsored generation as an alternative to both QFs and a utility generation monopoly.

Soon after the Energy Policy Act of 1992, a number of states (including those that had created the greatest surpluses of QF contracts) began to consider deregulation of the generating sector including, in many cases, the divestiture of utility owned generation (which then would become EWGs). As the 1990s progressed, the development of regional transmission entities and power markets, deregulation of generation pricing and investments, and retail access progressed. While the California crisis of 2000-2001 curtailed the spread of retail access and full reliance on markets to provide needed generation, the restructuring of the industry already encompassed more than half of the country.

Q. In the period after the Energy Policy Act of 1992, was there a decline in the amount of, and interest in QFs?

A. Yes. Generally, increasing focus on reorganization of the electricity sector, the creation of RTOs and retail access put the avoided cost issue on the back burner as a policy matter. The adoption of bidding that included EWGs along with QFs as a means of procuring power and meeting PURPA obligations, lower fuel prices and price forecasts and changes in avoided cost methodologies in some states made PURPA contracts less attractive for developers. Indeed, the predominant PURPA issue in the 1990s was how to unwind uneconomic QF contracts as part of electricity sector restructuring.

Q. What resulted from the Energy Policy Act of 2005?

A. The advent of retail access and creation of regional entities with non-discriminatory transmission access eliminated the basis for the anti-discrimination purposes of PURPA in affected parts of the country. Further, utilities that lacked retail monopolies no longer had the assurance that any excess PURPA-related costs could be passed through to customers. After successive attempts to eliminate PURPA Section 210 in its entirety, proponents convinced Congress to include amendments to PURPA in the Energy Policy Act of 2005 ("EPAct"). Of greatest relevance, a new Part M of PURPA exempted utilities in designated RTOs)from the Section 210 purchase requirement for all but small power plants. Utilities outside of these RTOs were given the opportunity to demonstrate to FERC that QFs connected to them had comparable competitive access and to thereby gain exemption. If this demonstration was made, FERC would be obligated to exempt the utility from the purchase obligation.

The consequence of exemption is that projects that would have qualified as QFs no longer have a counterparty who must buy from them. Since they have non-discriminatory access to markets, in particular the spot markets of the RTOs, the original purposes of PURPA are deemed by Congress to have been satisfied and, having found that such access exists, FERC not only could but must eliminate the QF purchase requirement.

Q. Did EPAct cause a rethinking of avoided cost methodologies?

A. To at least some degree. The passage of the Energy Policy Act of 2005 and a requirement that FERC implement changes in its regulations to reflect it[18] highlighted the limited intention of Section 210. While EPAct only abolished the PURPA requirement in the four Eastern RTOs and in ERCOT, and created an opportunity for utilities in the Southwest Power Pool and in California to become exempt, the criteria for exemption clarified that all PUPRA required was a non-discriminatory opportunity for QFs to receive market prices. This created a fresh benchmark against which the avoided cost methods of other

[18] There were only two changes relevant to Section 210, the only part of PURPA dealing with QFs. A new Part M allowed utilities in RTOs with certain characteristics to be exempt from entering into new or renewed QF contracts and spelled out the circumstances under which other utilities could become exempt. The new Part N eliminated QF rights for what were usually referred to as "PURPA machines," cogeneration facilities for which the non-electric use was minor and often contrived.

utilities that remained subject to essentially unchanged requirements to purchase QF power could be compared.[19] Because FERC had not made major changes in its regulations since 1980, some saw EPAct as a triggering event for remedying elements of the FERC regulations that had been shown to cause serious problems for the industry.

Q. Please explain how EPAct clarified the core requirements of a PURPA-compliant procurement methodology.

A. The EPAct provision that exempted utilities in RTOs from PURPA is highly instructive of what Congress considered to be the core reason for the PURPA requirement. Essentially, what Congress concluded was that if a QF was located in an RTO or similar market, then it had access to a competitive market and was thereby assured of non-discriminatory prices. The competitive market that is the *sine qua non* of an RTO is a real time spot market. No RTO requires any load serving entity to purchase energy bilaterally on a long-term basis and the longest term for a guaranteed capacity price in any RTO is three years.

The fact that membership in an RTO was a sufficient basis for exemption therefore clarified which commonly included elements of PUPRA implementation were not required by the law. There is no need for "bankable" long-term

[19] As implemented by FERC, the new Part M allowed other utilities outside of the RTOs to become exempt if they could demonstrate that QFs in their Balancing Authority Areas had access to competitive markets that was at least as favorable as access to RTO spot markets.

contracts or the shifting of price risk from the generator to a utility. Capacity payments, which exist at all in only some of the exempted markets, are not guaranteed for any material length of time and are reduced substantially whenever there is excess capacity. No exempt load serving entity is required or expected to buy capacity or energy in excess of its anticipated needs.

Q. You have been focusing on legislative and regulatory events. Were there changes in electricity markets in the last decade that also impacted PUPRA compliance?

A. Yes. One important change was the improved economics of energy limited, non-dispatchable generation that qualified as QFs. Wind, and later some forms of solar became significantly more economic. In the case of wind, this was due to several factors: wind turbine and blade technological improvements in the 1990s, a series of bills in Congress that created and then extended significant subsidies, additional subsidies in some states, and high gas prices for much of the decade. These factors made wind-powered generation approximately equal in cost to conventional alternatives, at least for so long as subsidies remained and gas prices were expected to remain high. As in the mid-1980s, bankable contracts based on high fuel price expectations led to a new wave of PURPA activity, with a renewed "gold rush" in geographic areas with good wind regimes and/or relatively high prices for PURPA power.[20] The growth of wind power has continued, although substantial reductions in current and anticipated gas price, the possibility of subsidies lapsing, and the lack of adoption of national carbon legislation have curtailed it in the recent past.

Q. Does the nature of these new types of non-dispatchable generation have importance for how avoided costs should be established?

A. Yes. I stated earlier that much of the first wave of QFs had characteristics similar to the conventional utility plant used in many states as a benchmark for establishing avoided costs. Non-dispatchable, intermittent resources have quite different characteristics. I will opine later that these differences are so profound that methods long used in a number of states for estimating avoided costs are now categorically inappropriate.

IV. AVOIDED COST METHODS IN OTHER JURISDICTIONS

Q. You stated earlier that you would discuss the various avoided cost methods in use. Please introduce this section of your testimony.

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[20] While the efficient scale of wind farms approaches and may exceed the upper limit of PURPA, developers often have been allowed to split the farms up into projects that are small enough to qualify.

A. I will first discuss two studies that reviewed avoided cost practices at different points in time. These are an exhaustive survey of methods conducted by National Economic Research Associates ("NERA"), a utility economics consulting firm, in 1990 and a paper written by The Brattle Group, also a utility economics consulting firm, for the Edison Electric Institute ("EEI") shortly after EPAct was passed in 2005. I will also discuss a sampling of state methodologies in use currently.

1990 Survey of Avoided Cost Methods

Q. Please describe the 1990 study.

A. In 1990 NERA surveyed avoided cost methodologies. They received responses from 60 utilities and 49 states.[21] The results of the survey were published in 1992,[22] and covered both the marginal cost methodologies used in setting retail electricity rates and the avoided cost methodologies used in setting prices paid to QFs. While the survey is more than 20 years old, it still is

[21] Delaware did not respond.

[22] Parmesano, Hethie and Bridgman, William, *The Role and Nature of Marginal And Avoided Costs in Ratemaking; A Survey*, NERA, January 1992.

representative of administratively determined avoided cost methods in use today.[23]

Q. Did the survey uncover a variety of methods for setting avoided costs?

A. Yes. As stated earlier, FERC allowed states quite wide latitude in PURPA compliance, including selection of methods for determining avoided costs. Moreover, in some states, regulators permitted utilities to devise their own methodologies, so that more than one existed. Also, as in Idaho, some states employed different methods for contracts of differing types or project sizes, contract durations, and firmness of power deliveries.

Q. Did NERA summarize the frequency of selection of the various types of avoided cost methodologies?

A. Yes. NERA assigned the states' avoided cost methodologies into five groups, apart from "other." While there were only 49 states that replied, attribution numbers are larger due to states that had multiple methods. The groupings were:

1. Least-Cost Capacity Option. Attributed to 13 states. In this method, capacity value was based on

[23] The exception is the use of bidding. As described previously, bidding was sanctioned by FERC in a 1988 Notice of Proposed Rule Making that did not ultimately become adopted into its regulations. Despite the fact that bidding began in the late 1980s as a method of selecting new resources and determining price levels paid to them, including QFs, the NERA survey does not discuss any bidding-based avoided cost methodologies.

the cost of a peaker. The peaker cost was net of energy profits in at least some cases.[24] Generally, capacity cost was not credited to the QF until capacity was needed by the utility.[25] Avoided energy was based on the marginal dispatch cost of the utility, often referred to as "system lambda."

2. Proxy Unit "A." Attributed to 11 states. Capacity costs were the capacity cost of the avoided unit, sometimes but not always the next unit in the utility's resource plan. Avoided energy was based on the cost of energy produced by the proxy unit. This is conceptually similar to the Idaho SAR methodology.

3. Proxy Unit "B." Attributed to six states. This differs from Proxy Unit A in that any capacity cost of the proxy unit that was in excess of such costs for a peaker were not included in capacity value but

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[24] As discussed elsewhere, it is a very common practice today to offset part of the carrying cost of the avoided cost unit with the margins expected to be earned from sales of energy and ancillary services. This offset was less important in the 1980s for two reasons. First, the significant improvement in technology that markedly lowered the heat rate for new peaking plants had not yet occurred so that they earned little if any margin on energy relative to the utility's marginal cost/system lambda. Second, energy margins in 1980s avoided cost calculations were computed relative to system lambdas, not relative to market prices as became more common after the restructuring of the electricity industry in much of the country. If margins are computed relative to system lambda, by definition there never is an energy margin for the highest cost unit dispatched.

[25] Excess capacity was rampant in the 1980s as a result of load that was much lower than had be expected in the mid-1970s when construction of long lead time, large (primarily coal and nuclear) baseload stations was initiated.

rather were added to energy value.[26] If the proxy unit is indeed more economic than adding a peaker, the avoided capacity cost under this method should be at or below the cost if the least cost capacity (peaker) method were used.

4. Differential Revenue Requirements. Attributed to 13 states. Avoided costs were calculated by comparing the cost of the system with the QF included (but treated as a zero cost resource) in comparison to the cost of the system without the QF. This comparison was based on the resource plan that existed if the QF did not exist. This method could look similar to a least cost capacity method, but if the QF merely postpones a utility unit and/or if the QF is large enough to affect the utilities system lambda, results will differ. Implicit in the methodology, no capacity costs were included for years in which capacity was unneeded. This is the method that NERA attributed to Idaho in the survey.

5. Cost of Purchased Power. Attributed to 2 states. In both cases, purchased power costs were the cost of economy purchases which at that time typically were split-savings rates. The methodology was used only for

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[26] The economic theory concerning utility resource selection is that a utility that needs capacity will build the lowest capital cost unit (i.e., a peaker). However, it will build another type of unit that has higher capital cost in preference to a peaker if the energy savings value of the alternative unit justifies its higher capital cost. In this sense, the higher capital cost for a baseload or intermediate unit is for the production of energy, not for capacity.

non-dispatchable QFs. Both states using this method used Proxy Unit A for dispatchable contracts.

6. Avoided Energy Cost Only (No Capacity). Attributed to 15 states, including most states in the Southeast. In a few cases, this treatment was limited to short-term power sales, with other QFs treated differently. It is possible that the prevalence of this method in 1990 reflected the large amounts of excess capacity that existed at that time.

Masked by this grouping were differences in details. One category worth mentioning was the assumption about QF quantities used for computing avoided energy costs. Methods varied from using energy cost simulation assuming no QFs, assuming the QF was in the resource mix, and (in the Differential Revenue Requirements method) computing the incremental cost savings either for each QF individually or the savings for all QFs collectively.

The Energy Policy Act of 2005 and the 2006 EEI Paper

Q. What was the purpose of the 2005 EEI paper?

A. As FERC was considering how to implement the relevant parts of EPAct, the Edison Electric Institute weighed in with a commissioned paper[27] that characterized the types of existing methodologies, identified

[27] Edison Electric Institute, *PURPA: Making the Sequel Better than the Original,* December 2006. The paper was prepared by the Brattle Group.

shortcomings and proposed changes. The passage of the Energy Policy Act of 2005 and a requirement that FERC implement changes in its regulations to reflect it had sparked a renewed interest in avoided cost rate methodologies. Because FERC had not made major changes in its regulations since 1980, this was seen as an opportunity to remedy elements of the FERC regulations that had been shown to cause serious problems for the industry.

Q. What is the purpose of reviewing this paper?

A. This paper is a useful, albeit short, summary of what had been learned about PURPA in the first 25 years of its operation. It also provides a brief critique of the avoided cost methods and contracts based on that experience and makes suggestions concerning how FERC could improve PURPA Section 210 implementation.

Q. How does this paper classify avoided cost calculation methods?

A. The taxonomy of administrative methods for setting avoided costs discussed in the EEI study was similar to that used by NERA 15 years earlier. These were:

1. <u>The Proxy or Committed Unit Method</u>. This method, also called the proxy unit method in the NERA paper, assumed that the QF delayed or replaced the next planned generating unit in the utility's IRP. Avoided costs were therefore based on the projected capacity and

energy costs for that unit. Financing cost parameters and discount rates for levelization were based on the utility's cost of capital. Adjustments generally included modifying capacity costs to account for in-service timing differences. The authors noted that the proxy unit method was one of the simplest types in that it did not require production cost modeling. Implicit in that simplicity, however, is that the avoided costs are not modified to take into account differences such as availability and capacity factor between the proxy and QF unit.

2. The Component/Peaker Method. This is what NERA termed the lowest cost unit method. The avoided capacity cost is the lowest cost form of capacity, generally assumed to be a combustion turbine. The EEI paper's description is silent on whether the capacity cost was net of margins above variable cost earned in energy and ancillary services markets. In fact, most of the initial adoptions of this method had no such offsets, which only became important when improved turbine technology substantially reduced heat rates and hence resulted in operating profits for new peakers since market prices and/or lambdas now were sometimes set by less efficient units. The avoided energy cost is the utility's marginal cost of generation over all hours of the year, but could include only those hours when the QF would produce power.

Implicitly, the methodology assumes that the existence of the QF does not affect the utilities' marginal cost.

3. Differential Revenue Requirements Method. In its most complex form, this method first requires that the utility's expansion plan be reoptomized to take into account the existence of the QF(s). The existing system is then dispatched as is the reoptomized system (with the QF treated as having zero costs). Differential revenue requirements, including any differences in capital costs, constitute the QF avoided costs. This method differs from the component/peaker method in that it expressly determines the avoided capacity within the analysis and inherently reflects the dispatch pattern of the QF.

All of these methods identified above were regulatory in nature. That is, avoided cost "discovery" was based on calculations made or approved as part of a regulatory process rather than by observing prices in the market.[28] As discussed previously, at the time that PURPA was adopted, utilities were vertically integrated and there were no organized power markets. Indeed, it was this lack of competitive options for cogeneration and small power

[28] An exception is that in the component/peaker and differential revenue requirements methods, the market cost of purchases could be a component if, for example, the utility had an avoidable offer of purchased power. I shall note that Sierra Pacific had complained that the Nevada Commission ignored this possibility in a proxy method avoided cost computation.

facilities that motivated Congress to include Section 210 in PURPA.

The EEI paper also discussed auction-based avoided cost methods. It noted that auction-type procurements were adopted largely in response to the poor performance of administrative methods of avoided cost estimation. It also stated that a primary reason for adopting auctions was to limit the amount of QF energy and capacity purchased and to be able to select the cheapest and/or most beneficial. It noted that there was a great deal of variety in how procurements were conducted, particularly in how scoring was done, with self-scoring of bids according to previously established, transparent scoring systems being at one extreme and a wholly opaque, partly qualitative determination of winners by the utility at the other. The paper also discussed the portions of the FERC Auction NOPR, RM88-5, that discussed what types of auctions were consistent with PURPA requirements. The authors also stated that the auction-based procurements that were used by several utilities to meet their PURPA obligations were generally consistent with the NOPR, except that not all embraced the proposed all-source requirements.

Q. Did the paper comment on the advantages and drawbacks of the various administrative methods of avoided cost calculation?

A. Yes. The authors viewed the proxy unit method as the least attractive method of determining avoided cost. They noted that in many cases the proxy unit was not even one that the utility would plan to build. Even if it was a planned unit, the QFs being offered and getting a price based on the proxy unit's cost may be too dissimilar in terms of, for example, reliability or the times when power from the QF was available. They also noted that the proxy unit method did not allow for reoptomizing the planned system to take into account the output from QFs. This proved to be a major drawback in areas where QF entry was substantial in relation to the size of the utility.

The differential revenue requirements method and the component/peaker method were regarded as more sophisticated and conceptually correct, but more complex and opaque. The differential revenue requirements method also is the only one that models the impact of the QF on system lambda.

Q. Did the authors comment on the performance of these administrative methods collectively?

A. Yes. They stated that all such methods require judgment about such uncertain factors as fuel cost, cost of capital, escalation in labor and equipment costs, demand growth, and so forth. As it turned out, errors in these forecasts, particularly fuel price forecasts caused then-historic long-term avoided cost forecasts to be too high irrespective of the method used.[29] They note rather wryly that proxy methods based on coal units likely were the least wrong (despite the fact that few coal units were actually initiated during the period) because the estimate of coal price escalation was substantially lower than similar estimates for oil and gas and hence closer to what actually transpired.

Q. Did the authors discuss the specific types of errors that had been made in administrative avoided cost approaches?

A. Yes. The authors grouped their comments under six headings:

1. Intentionally Setting Rates Above Avoided Costs. In a few cases, states deliberately set rates above avoided costs. The example they use is the New York six-cent minimum that the NYPSC Chair testified to FERC was well above any of the state's utilities' avoided cost.

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[29] It should be noted that such forecast errors are not limited to administrative methods of estimation. If participants in an auction have a consensus of similarly incorrect expectations, auction-based prices will be similarly wrong. The forecasting problem is not related to the method so much as to the enormous risk of forecasting and then fixing prices, no matter what the method.

2. <u>Requiring Capacity Cost Payments Even Though the Utility Does Not Need New Capacity</u>. This was discussed as primarily a consequence of standard offer rates. However, the authors report that the California Public Utilities Commission ("CPUC") deliberately required capacity payments when no capacity was needed to meet reserve margin targets on the grounds that all capacity makes at least some contribution to reliability.

3. <u>Standard Offer Rates Without Quantity Limits</u>. While FERC only required standard offer rates for QFs of 100 kW or less, many states allowed standard offer rates for larger projects. As noted previously, California made its standard offer rates available to all projects. Since the rates were very attractive to developers, the state was swamped with projects.

4. <u>Long-term Contracts with Fixed Rates</u>. As the authors had already noted, forecasts of long-term prices will inevitably be wrong. While it can be hoped that the errors will even out to zero, this has not been the experience. While comments received by FERC in 1987 had argued for reopeners or other methods for limiting long-term contract price risk, FERC had not acted to limit the ability of states to require long-term contracts. A related problem noted in the paper was the front-loading of

costs that raised intergenerational equity and out-year performance risk issues.

5. General Errors in Avoided Cost Methodology. This was a catch-all category. Two examples were given. One relates to proxy unit methods where the avoided cost unit was one that actually was under construction. In such cases, the authors argue that the sunk costs of the unit should not be included in avoided cost calculations. The second example was failure to take power purchase alternatives into account in setting avoided costs. The example given was in Nevada; there the rate was set at 6.3 cents, notwithstanding that the utility's planned next addition was a firm purchase at a much lower cost.

6. Paying the Same Rate to QFs, Regardless of Their Characteristics. From the historical perspective taken in the paper, this problem arose primarily from the baseload-like nature of most QFs built in the earlier years of PURPA. Since QFs had the right to be paid for all power generated, and prices were above the units' marginal costs, these units performed like must-run baseload units. In areas where quantities grew large enough, or where the utility already was long baseload generation, this created operational as well as financial problems for the utilities. While dispatchability had been one of the

factors that FERC had expressly called for states to take into account in setting avoided cost rates, in the states discussed in the paper there was no price differentiation for dispatchable units. Of course, this problem remains since these are characteristics of wind and solar power.

Q. What does the report say was the response to these errors?

A. The primary response that the paper discussed was the development of competitive procurement as an alternative to administrative methods. The report acknowledges that this is not a panacea, since long-term fixed prices can lead to serious over (or under) payment no matter how set. Nonetheless, the authors conclude that "prior to the industry disruption caused on retail competition and restructuring, competitive procurement of QF capacity was exhibiting promise as a means of correcting some of the problems associated with administrative determinations of avoided costs."

A Sampling of Current Avoided Cost Methods

Q. Thus far, you have discussed primarily the avoided cost methods that were established in the 1980s. Have you also reviewed some of the innovations that have taken place since that time?

A. Yes. I will focus particular attention on California. It had one of the most painful experiences resulting from having made mistakes in PURPA implementation in the 1980s and hence is likely to be mindful of lessons learned.

I do not suggest that California is the template for Idaho to follow. The California solution was a compromise among interests and, like all compromises, is not perfect. Further California had characteristics not necessarily shared by Idaho: a large installed base of QFs coming up for recontracting and a very aggressive renewables requirement being two obvious examples.

Other states have meritorious solutions to the avoided cost problem that also are worthy of consideration. I will discuss a sampling, highlighting features that I believe to be of particular interest or merit.

Q. Please provide some background on the reformation of the California methods of determining avoided costs.

A. As discussed previously, California has very substantial amounts of PURPA power. Much of that capacity was signed up under Standard Offer 4 ("SO4"). SO4 fixed forecasted energy prices just before gas prices collapsed and hence was highly profitable, particularly but not uniquely for gas-fired cogeneration. SO4 had no ceiling quantity amount and, according to Southern California Edison, by early 1987 caused total QF contracts in

California to rise to 16,000 MW, notwithstanding that SO4 existed only from April 1983 until it was suspended in September 1984. SO4 QFs received 10- to 30-year contracts with fixed capacity payments and 10 years of predetermined energy payments. The very high costs and substantial amounts of capacity were illustrated in comments provided to the FERC in 1987. For example, Pacific Gas and Electric Company ("PG&E") testified at a FERC-sponsored regional conference (memorialized in FERC Docket No. RM87-12-000) that by 1990 its QF overpayments would reach an estimated $857 million per year. It cited to a California Energy Commission estimate made in 1986 that, as a result of its QFs, PG&E would need no new capacity before the late 1990s.

At the time that settlement talks were underway, many of the QF contracts were expiring and projects were seeking new contracts, to which they were entitled under PURPA. During this same time frame, California was adopting numerous "green" policies, including renewable quotas, such as separate utility quotas for different types of renewable and cogenerated power. On the other side, in implementing EPAct, FERC had invited the California utilities to apply for exempt status, which would result in existing QFs losing PURPA as a basis for demanding contracts altogether.[30] This confluence of events created a climate for a settlement covering utility procurement of both QFs and other, non-QF cogeneration and renewable power.

California utilities, cogeneration and combined heat and power QF owners, and ratepayer advocacy groups negotiated for 16 months and entered into a settlement Agreement ("QF/CHP Settlement") approved by the CPUC in December 2010. The QF/CHP Settlement resolved QF-related disputes before the CPUC and the courts, established a new QF/CHP Program in California, made available additional power purchase agreement ("PPA") options for QFs under the QF/CHP Program, including a PURPA program for new PPAs for QFs of 20 MW and smaller, and established a transition phasing out QF status for QFs with greater than 20 MW net output.

In June 2011, FERC found that the utilities in the California Independent System Operator ("ISO") qualified for exemption from PURPA Section 210 purchase requirements,

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[30] In its 2006 Order, FERC determined that the exemption would not apply, even for the five RTOs entitled to exemption, for QFs with maximum capacities less than 20 MW. The 20 MW limit was very different from the statutory 100 MW entitlement to a rate based on a schedule. It is interesting that in 1987, FERC had opined that 1 MW was an appropriate limit for exempting QFs from having to participate in all-source procurements for states that had such methods for procuring power. It is not clear why utilities are believed to need to serve as aggregators for small QFs. The reason may be that the RTO membership fees are substantial.

with the exception of QFs smaller than 20 MW for which exemption had not been sought.

Q. Please explain the main attributes of the new California procurement of cogeneration and renewable power.

A. The settlement has various procurement mechanisms. It should be understood that the settlement is not just about PURPA QFs, but also about non-QF renewables. Under the QF/CHP settlement, a new, competitive procurement process was adopted in lieu of the previous system of PUC-ordered standard offer contracts. A primary mechanism created in the QF/CHP Settlement is a CHP Request for Offers ("RFO") process that allows the state's three large utilities to run competitive, transparent RFOs for CHP resources. It puts CHP resources into a process similar to the competitive procurement processes that already had been established for conventional resource and Renewable Portfolio ("RPS") procurement. The settlement also allows utilities to use non-RFO processes such as bilateral contracting, renewables feed-in tariffs, a PURPA Program for QFs under 20 MW, direct utility ownership, and other procurement options. Allowing CHP developers to bid into the RFO allows them to propose prices that are sufficient to finance and develop their facilities, while at the same time allowing the IOUs to pick the best offers based on a number of criteria, including price.

The QF/CHP Settlement further establishes procurement "MW Targets" for each of the California IOUs under the QF/CHP Program. Overall, the target is 3,000 MW of new or repowered projects for the decade beginning 2010.

Q. Does California have a standard offer specific to QFs?

A. Yes. The pro forma PPA for QFs of 20 MW or less is available to QFs with firm or as-available capacity of less than 20 MW, regardless of whether the QF has submitted an offer in the RFO or seeks alternative contracting options. The PPA for QFs of 20 MW or less contains standard terms and conditions and incorporates the peaker-based capacity prices established in prior PUC decisions.[31] For energy prices, the QF/CHP Settlement establishes Short-Run Avoided Cost ("SRAC") that transitions to a market (rather than administratively determined) heat rate by January 1, 2015.[32] New or repowered facilities must post project development security and performance assurance. The term is up to 7 years for existing capacity, and up to 12 years for new capacity.

[31] Capacity pricing is pursuant to D. 07-09-040, with Firm Capacity at $91.97/kW-yr and As-Available Capacity of $41.22/kW-yr escalating each year.

[32] The California Public Utilities Commission has set SRAC energy prices using a variation of the following formula for many years: SRAC Energy Price = Fuel Price x Heat Rate + O&M Adder. The regulatory heat rate in existence at the time of the settlement was in excess of 9000 BTU/kWh, which was higher than the heat rate implied by the market price of power.

QFs of 20 MW or less are included in the Procurement MW Targets for each of the California IOUs, so that while there is no limit on QFs as such, the 3,000 MW overall limit is in force.

QFs with as-available capacity receive SRAC energy payments along with an as-available capacity payment. QFs providing unit firm capacity also receive SRAC energy payments and higher capacity payments reflect the value of assured long term firm capacity.

The standard terms for new PURPA contracts are essentially identical to the contract terms for non-QF CHPs. The capacity price component is set in advance for the length of the contract (12 years for new or repowered capacity). The performance requirements to qualify for firm capacity payments are steep: earning a full payment requires an availability of 95 percent and no payment is available for availabilities of less than 60 percent. As-available capacity payments also are subject to non-availability penalties.

Q. Are energy payments fixed for the duration of the QF contract?

A. No. An important change from prior California QF contracts is that energy prices are reset annually rather than fixed in advance for the term of the contract. The SRAC price is set based on 12 months of forward prices.[33] Both capacity and energy prices are time differentiated into two seasons and several time-of-use periods.

Q. How does the QF contract treat the green attributes of QF contracts?

A. The contracts entitle the buyer to all energy and capacity from the QF as well as all of the green attributes of the power production. The price paid for energy from the QF includes any greenhouse gas charges that may be assessed on it based on its fuels type and efficiency.

Q. Does California have other renewable resource program specific to PURPA qualifying resources?

A. Yes. The Renewable Auction Mechanism, or RAM, is a market-based procurement mechanism for distributed renewable generation projects up to 20 MW delivered on the system side of the meter. The California PUC authorized the utilities to procure an initial 1,000 MW through RAM. Under the market-based pricing in the RAM, sellers compete for a contract in a renewable auction mechanism, bids are

[33] Due to a peculiarity of California law, the energy prices must be indexed to gas prices. Between 2011 and 2015, the heat rate used to convert forecast gas prices to electricity prices declines to the "market heat rate." The market heat rate is the heat rate implied by the 12 month forward electricity prices in the relevant zone (northern or southern California). The effect of using a market heat rate, so defined, is to convert the gas price formula to one that prices energy based on the forecast electricity prices in the zone, as forecasted by three separate commercial services and based principally on forward bilateral transaction prices.

selected by least-cost price first until the auction capacity is reached. Further negotiation is not allowed. The price is the as-bid price of the QF, not a market clearing price for the totality of winning bids.

Q. Does California have a program for buying QF power on the basis of schedules, as PURPA requires for resources of less than 100 kW?

A. Yes. For smaller scale renewable resources, "feed-in tariffs" are used to purchase power under predefined terms and conditions, without contract negotiations or participation in a competitive solicitation. Use of feed-in tariffs are restricted in terms of the types of QFs that qualify to a maximum size of 1.5 MW and aggregate quantity (initially, less than 500 MW, statewide).

Q. You had said earlier that California had been a poster child for excess prices and quantities of PURPA power in the 1980s. What are the primary areas of improvement in the current California avoided cost methodology?

A. First of all, since only projects of less than 20 MW are eligible for PURPA-based contracts, the likelihood of great excesses of unneeded power is much reduced. Second, California quit requiring utilities to offer pre-determined energy prices in their long-term contracts. While contracts are up to 12 years long (a shorter period than under the earlier standard offers), energy prices are set only one year in advance. Effectively, they are based on market energy price forecasts. Prices are time-differentiated so that the energy price received by the QF depends on when energy is produced. Capacity prices are set at contract inception for the full term, but are varied according to the firmness of capacity, plant availability, and the time at which energy is produced by the QF.

The California QF contracts are non-discriminatory in that QFs are paid on a basis very similar to non-QF projects. That is, there is little advantage to qualifying as a QF since essentially identical contract terms are available under other state programs for non-qualifying CHP and renewable power. Moreover, since the bulk of CHP and renewable power is not PURPA eligible, there is no impediment to the state limiting the total amount of such power to that which is needed for reliability or to meet other state objectives since QFs count toward the relevant overall targets.

An exception to the lack of long-term fixed prices is the program for purchases of renewable power from projects of less than 1.5 MW. However, eligibility under this program is severely quantity limited.

Q. Are there aspects of the California solution that will pay QFs prices that are above avoided costs?

A. This is matter of interpretation. It had been long-standing FERC policy that avoided cost had to be set with reference to all potential sources of power. This was applied specifically to California in a FERC order in case EL95-16-001. This decision found that a CPUC order requiring utilities to buy QF power in an auction process in which participation was limited to QFs violated PURPA, since prices determined in such an auction could exceed prices available from non-QF alternatives. By this standard, the renewables-only auctions in the current California scheme can result in overpayments.

However, as part of revisiting PURPA and renewables development that I have just discussed, the CPUC petitioned FERC for determination of whether feed-in tariffs and other mechanisms limited to QFs violated PURPA. In EL10-64-001, FERC essentially reversed its earlier order. It reasoned that when a state had a renewable portfolio standard, power from sources that do not qualify as renewable cannot be used to meet the requirement. Hence, the lowest cost available resource that qualifies as renewable is the avoided cost for meeting the RPS requirement. Hence, a competition restricted to renewable resources can validly set an avoided cost that is consistent with PURPA.

From this I infer that the mechanisms created in California for estimating the PURPA avoided cost for renewables that allow payments greater than made to non-renewables are lawful, at least in California. However, their validity would seem to depend on the existence of a bright line renewable resource procurement requirement with firm and specific renewable resource quotas and based on the EL110-64-001 would seem to be valid only under those circumstances.

Innovations in Various Other States

Q. What is the purpose of this section of your testimony?

A. While I have discussed the categories of avoided cost methods, there are important details within a type of method that Idaho may wish to consider. I have reviewed several different avoided cost methodologies and extracted some of the features of them.[34]

Q. What is the first topic you will discuss?

A. The first topic is the use of visible market prices for calculating avoided costs.

As I discussed previously, the Energy Policy Act of 2005 mandated that utilities in the five original RTOs were

[34] Reviews were either from original source documents or from summaries contained in a 2011 study sponsored by the Southern Alliance for Clean Energy, authored by a Ms. Carolyn Elefant, titled "Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Proposed Path for Reform," available at www.carolynelefant.com.

eligible for exemption from PURPA section 210 altogether. Hence, projects that previously would have been QFs in those areas are dependent on either bilateral contracts with utilities or the visible markets conducted by the RTOs for revenue. Most such contracts are short run in nature; state-supervised auctions typically are for three years or less. RTO power markets are even shorter term, with prices varying even within the hour and prices set at most a day ahead. Capacity typically is bought on a monthly, seasonal, or annual basis in those RTOs that have capacity markets.

Power markets are also used in several instances to set avoided cost rates where the utility is not exempt. California is one example. Energy prices for QFs except the smallest ones are set based on one year forward market prices. Other states using market prices for at least some QFs include utilities in RTOs in the period prior to exemption, for which Massachusetts is an example, Southwestern Public Service ("SPS"), which is in an RTO but is not exempt, Oregon, which uses market prices for energy when a utility does not need capacity, and Progress Energy-Carolinas, that offers market prices as an option that a QF can select.

Q. How did Massachusetts set avoided cost prices prior to the blanket PURPA exemption for ISO-New England utilities?

A. Massachusetts was one of the earliest states to restructure. Its utilities sold their generation and bought their provider of last resort power from ISO markets. These same markets were available to all power suppliers, including QFs. When Massachusetts utilities still had obligations to purchase from QFs under PURPA, they were allowed to satisfy the obligation by taking title to the power, and paying the ISO-NE spot energy price at the QFs location for power, as well as the locational price for capacity set in the ISO-NE market.

Q. Please explain how SPS uses market prices to set avoided costs.

A. SPS is a member of the Southwest Power Pool ("SPP"). SPP utilities did not qualify automatically for exemption, but FERC invited its members (similarly to the CAISO member utilities) to apply for exemption. SPS and two other SPP member utilities applied jointly for exemption in 2008. While the other two utilities gained exemption, FERC found that QFs in SPS might not have sufficient access to markets to cause FERC to grant an exemption. SPS continues, therefore, to be required to buy QF power under PURPA. However, both the Texas and Oklahoma state regulators have concluded that SPS can meet its PURPA responsibilities by buying power from the QFs and paying them the price they would receive if they sold into the SPS balancing market. The reasoning is that the sole cause of SPS being denied exemption is because of market access concerns, not concerns over the appropriateness of market prices as measures of avoided costs. SPS's agreement to pay the market price irrespective of whether the power could be delivered outside of its BAA solved the market access problem.

Q. How does Oregon use market prices to set avoided costs?

A. Oregon distinguishes between avoided cost methods for near-term periods when utilities have sufficient resources to meet reliability requirements and longer term periods when new resources are needed. Oregon uses the proxy methodology for the future, resource deficit periods. It uses monthly on-peak and off-peak forward prices as of the time of contract signing for the near term, resource adequate period. No capacity payment is made during that period.

Q. How are market prices used in North Carolina?

A. In North Carolina each utility has its own primary method for setting avoided costs. Both the peaker and IRP methods are permitted. Progress Energy uses the

IRP method. It offers standard contracts for units up to five MW (three MW for hydro) with the standard contract based on a generic version of the QF type (e.g., solar, municipal waste, or wind). As an alternative, the QF can elect to be paid the locational marginal price calculated by the Pennsylvania-Jersey-Maryland ("PJM") RTO at its interconnection with Progress Energy. This is somewhat different than for SPS and the Massachusetts utilities since Progress Energy is not in PJM. Rather, PJM is used as the closest market with a competitively set, visible market price.

Q. Do you have any examples of utilities using auction or RFP methods to set prices?

A. Yes. An example is Georgia using competitive bidding to set its avoided costs. The RFP quantity is based on the utility's needs. All QFs of five MW or more must bid in response to the RFP and receive a contract only if they are winning bidders. Smaller QFs can get the RFP price without participating.

Q. Can you provide any examples of creative approaches using administrative methods for setting avoided costs?

A. Yes. Florida uses the next unit proxy unit method. What differentiates Florida from most other states using the method is that it is quite literal about using the utility's next unit as the proxy, in that the proxy unit is changed in response to changed circumstances, including contracting with QFs.

Each utility must identify the next avoidable unit in its resource plan. Avoided capital costs are based on the savings from deferring the unit, essentially the annual carrying costs, escalating at the construction cost escalation rate. If the avoided unit is on line well into the future, capital cost payments can begin at a time before the on-line date of the avoided unit, reflecting the need to commit resources to its construction if it is not avoided. Avoided energy costs are the energy costs of the avoided unit beginning when the avoided unit would have come on line. For periods before the on-line data of the avoided unit, only as-available energy payments are made. These are the *ex post* actual avoided costs arising from all of the QFs that are receiving as-available rates, averaged over the block of all such capacity. This is not the system lambda for two reasons. First, this averaging will reduce the energy price relative to a system lambda. Second, the calculation is made after first eliminating the energy used to serve interchange sales. That is, only the cost of energy that is avoided in meeting native load counts, as available QFs do not receive the higher cost of energy that only is generated to make off-system sales.

Q. Does the Florida QF offer system include tariff-like standard contracts?

A. Yes. These are available only to units of 100 kW or less. The regulations appear to contemplate that all other contracts are negotiated. The utility is not required to pay more than its avoided costs and must negotiate in good faith. The Commission may order the utility to sign a contract and penalize dealing in bad faith.

Q. Can Florida utilities limit the amount of QF capacity that they purchase?

A. Not directly, but there are specific mechanisms to change (lower) the price when sufficient capacity has been contracted.

Q. How does this mechanism work?

A. The proxy unit used to set avoided cost is a specific planned unit with defined capacity. The standing offer to QFs arising from the avoidance of that unit closes whenever an RFP to actually construct that unit is issued, when the amount of capacity needed to fully displace that unit has been contracted, or when the unit is removed from the utilities' resource plan for other reasons.

Closing the old offer triggers a new avoided cost based on what becomes the utilities avoided unit. Necessarily, this unit will have a later on line date than the unit that previously had set avoided costs. Usually this new avoided cost will be less attractive to QFs, if for no other reason because the period of time that will pass during which the QF receives no capacity payments and receives only *ex post* short run incremental cost for energy will be longer.

Q. What lessons do you draw from these examples?

A. From the examples of non-exempt utilities basing payments on actual market prices, I infer that this practice is acceptable to FERC and to at least some state regulatory commissions. From the Georgia example, I note that utilities still can rely on competitive procurement for limited quantities of energy and reject QF offers (other from small units) that do not win in the procurement. From the Florida regulations, I see that even proxy unit methods can result in limiting QF energy purchases and, at least in principle, avoid buying unneeded capacity or paying more than avoided costs. The Florida example also is interesting in its treatment of QF energy received before the avoided unit would have been on-line and in its exclusion of interchange sales in setting short run avoided cost of energy.

V. CURRENT AVOIDED COST OPTIONS AND RECOMMENDATIONS FOR IDAHO'S AVOIDED COST METHODOLOGY

Characterization of Types of Methods

Q. You have discussed various methods of calculating avoided cost at some considerable length. Would you please very briefly restate what categories of methods exist?

A. Presently there are two types of methods of determining avoided costs: administrative/regulatory determination and market revelation. Each can, in turn, be divided. To summarize:

1. Administrative/Regulatory.

a. Proxy Unit. There are several variants on this method; the core is that avoided costs are based on the capital costs and variable operating costs of a proxy unit which may be the next unit in the utilities resource plan, and commonly is a combined cycle or combustion turbine unit.

b. System simulation/IRP. The pure variant of this method requires injection of the QF into the utility's preferred resource plan, then reoptomizing new builds and resimulating system cost. Avoided cost is the difference between the two streams. A simpler version assumes that the next unit would have been a peaking unit and computes the capacity value of the QF based on the capital cost of the peaker, preferably calculated net of energy and ancillary services net revenues and adjusted for the on-peak availability of the QF. The QF's energy avoided cost is, as with the pure variant, based on simulation of marginal energy costs for the utility, but assuming that the incremental costs without the QF will also be the incremental costs when it is on-line.

2. Market Discovery.

a. RFP/Auction. The utility holds competitive procurement for a defined amount of power. The price set in the procurement is the utility's avoided cost, though non-price factors can be taken into account in selecting winners. The price usually is available to QFs only if they are winners in the auction. While FERC favored all-source procurements for such procurements, its recent EL10-64-001 decision (discussed in connection with California's avoided costs) allows auction arrangements limited to certain kinds of resources such as wind or solar under defined circumstances.

b. Market Pricing. This effectively is the substitute for avoided cost pricing and contracts in areas where PURPA exemption is available. As discussed in connection with SPS's Oklahoma and Texas tariffs, and Progress Energy's North Carolina's tariff, it also can be used where QF access to markets cannot be assured, but relevant competitive markets can be used as a benchmark for pricing PURPA power.

Q. Which of these methods currently is used in Idaho?

A. My understanding is that Idaho currently uses the proxy unit in its SAR methodology for smaller units and the simpler version of the system simulation/IRP method for larger units.

Discussion of Avoided Cost Calculation Methods

Q. You have discussed four types of methods of determining avoided costs. Is there a hierarchy in terms of how well they comport with the basic PURPA requirement that prices be at, but no higher than, the utility's avoided cost?

A. Market-based solutions are congruent with this requirement, almost by definition. Whether a price can be readily observed, as in the RTOs spot markets, or must be discovered, as in the structured procurement method, depends on where the utility is located. While a case can be made, and FERC at one time made that case, that market-based solutions are better than even the best administrative solution, market forecasts are simply consensus forecasts and have no *per se* claim to superiority over a properly conducted forecast made in the course of the utility's business or conducted as part of a regulatory or administrative process.[35]

Setting aside issues of convenience and transparency, which may be controlling for very small QFs, the preferable administrative method is the IRP method. The proxy unit method is clearly inaccurate, at least under today's circumstances. Various forms of the proxy unit method were initially the most commonly adopted. The virtue of the proxy method is simplicity and transparency. The method does not require forecasting the operation of the utility's system, but only the operating cost of the proxy unit. A single schedule of prices is derived and available for application to all QFs. This simplicity is also its Achilles Heel. Quite simply, it ignores the fact that different types of QFs have very different operating characteristics and hence allow the utility to avoid very different costs. This particularly is true of intermittent resources such as wind and solar and non-dispatchable and/or energy limited resources such as some hydroelectric facilities. I understand that these are likely to be the most common types of QFs in Idaho in the near future.

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[35] FERC's claim of superiority for auction methods of setting prices did not rest on the assumption that auction participants were better forecasters than utilities or regulators, but on the observation that if the utility actually purchased the lowest cost power offered to it, it was paying a proper avoided cost price for the product that was the subject of the auction, at least at that time.

Q. How are today's circumstances different from those that existed when most states adopted some form of proxy unit method?

A. There is a much greater mismatch between the characteristics of a proxy unit and the types of units being offered as QFs. A proxy unit anywhere in the U.S. most likely would be a gas-fired combustion turbine or a gas-fired combined cycle unit. Compared for example, to a wind farm, these types of units have excellent reliability and availability and hence value as capacity, and the ability to provide important ancillary services. Combined cycle units also are economic producers of energy much of the time, whereas the energy value of combustion turbines is limited as a result of high dispatch costs. Conversely, a wind farm has very little capacity value due to the high proportion of time when it cannot produce energy and a lack of diversity to other wind units, little if any positive ancillary services value and, indeed, impose integration costs arising primarily from the need for the utility to carry additional regulation. On the other hand, its energy production value typically is substantially greater than the combustion turbine and may be greater than a combined cycle unit where wind regimes are favorable and combined cycle units are uneconomic for significant portions of the year.

Q. Is it possible to adjust the proxy unit-derived avoided cost to create a reasonable estimate of the avoided costs applicable to the types of units that are seeking PURPA contracts?

A. To some degree, yes. For example, the capacity value of the QF can be adjusted from the proxy unit to reflect different availability. However, there still are important other differences that should be reflected in avoided cost but will not be. Use of a common proxy unit also distorts the relative avoided cost of different types of QFs. For example solar power produces energy that is disproportionately during high load periods but wind does not.

It could be argued that there is a place for a proxy unit for the rate schedule used for small QFs. This is the practice in Idaho, where the SAR-derived schedule is based on a proxy unit. However, using a single type of proxy unit still results in the same proportionate distortion as if the proxy unit method were applied universally. The size limit merely confines the damage.

Fortunately, there is no need to use a proxy unit, even for the published rate schedules that must be made available for small units. There is not, and never was, a requirement for a single rate schedule for small QFs, much less a single proxy unit. Instead, the set rate schedules can be developed separately for each of the main types of QFs. My understanding is that in Idaho these are wind power, irrigation-based hydro, and solar. Basing the rate schedule for wind QFs on a generic wind unit's avoided cost and a solar schedule on a generic photovoltaic unit's avoided cost, for example, greatly improves the accuracy and non-discriminatory nature of the schedules. A set of rate schedules that computes avoided costs with reference to the operating characteristics of generic units of the differing QF technologies makes use of the system simulation/IRP method instead of the proxy unit method. This is an element of the IPC proposal in this proceeding.

Q. Skipping over the system simulation method which I understand to be the primary focus of your recommendations, what are the virtues of the market-based methods?

A. Congress has determined that access to transparent and liquid markets achieves the goals of PURPA. This is reflected in the exemption of utilities in organized RTO markets from PURPA Section 210 obligations. Similar access to a liquid and transparent market outside of an RTO should be similarly sufficient to achieve the intended non-discriminatory effect. In the Idaho context, the closest transparent and visible market price is the mid-Columbia price. If the state's utilities were to pass through revenues that were based on the mid-Columbia price (with appropriate power firming, system integration, and transmission cost adjustments), the resultant avoided costs would be identical to the revenues that the QF would receive if Idaho were part of a market in which utilities qualify for exemption. This pricing could be done on an *ex post* basis. It also could be on an *ex ante* basis for up to two or three years (as is the case in Oregon), since reasonably thick and liquid markets exist for that period. Access to these forward markets permits both price discovery and an opportunity for the utilities to hedge their price commitments. If done on an *ex post* basis, this is essentially the result that would ensue if the Idaho utilities were exempt. The *ex ante* solution provides the QF with somewhat greater price certainty, without unduly burdening customers with price risks.

Q. Do you believe that this type of price discovery would be found by FERC to be consistent with PURPA, even if the Idaho utilities are not eligible for exemption?

A. Most likely, yes, but this is not entirely certain, particularly since the current FERC strongly promotes renewable generation and demand response as alternatives to fossil generation. But on the merits, it should be acceptable. Under this option, the market pricing of QF power is non-discriminatory, in that the QF gets a price based on the market price of power at which the Idaho utilities can and do buy and sell non-QF power. It also assures that Idaho ratepayers are not disadvantaged by paying more for power than they would pay non-QF sources. If, as it likely must be, market pricing is either *ex post* or based on forward markets that do not extend far into the future, it can essentially eliminate long-term contract risks.

Q. What would your response be to the argument that these short-term, market-based prices may not be high enough or firm enough to cause QFs to be built?

A. Quite simply, that PURPA never was intended to subsidize QFs. If the prices that utilities can buy power for in markets are too low to support a particular QF or type of QF, it is entirely consistent with PURPA that the QF is not built. Regarding the firmness of prices, it simply is not the case that long-term firm prices are required in order to get QFs or, for all that, non-QF merchant capacity built. A "bankable" contract makes it easier and cheaper to get high leverage project finance. However, nothing in PURPA mandates that customers should shoulder the price risks that make cheap financing available, especially since the reduced financing cost is not flowed through to them in lower power costs.

Q. Are there reasons why it might be preferable to use the second type of market pricing, the RFP, or action method?

A. The primary virtue of this type of procurement is that it can be tailored to acquire the types of capacity that the particular utility needs. Such procurements can, and have, given weight to the various factors that FERC said from the beginning of PURPA should be taken into account, such as firmness, dispatchability, fuels diversity, and so forth. I recognize that a procurement that seeks to weight these various non-price factors quickly becomes complex and arguably somewhat arbitrary, but there is now a considerable body of experience that could guide the development of such a methodology.

From a QF's perspective, a virtue of the RFP/auction process is that the QF sets its own bid level. Necessarily, the price set in the RFP is commercially acceptable, at least to the winners. By the nature of the procurement, QFs that can or will only accept higher prices will not be selected. Importantly, by limiting the quantity procured to the amount that the utility actually needs, the process shields ratepayers from the risk of paying what may be excessive amounts for power that is not needed and cannot be resold for the contract costs.

The RFP/auction method is best applied if there is a need for new power supplies. While it might be possible to have an energy-only auction when no capacity is needed, this is not likely to attract the entry of new suppliers. My understanding is that at least some Idaho utilities do not presently need new capacity beyond that already on-line or under construction and that IPC is also long energy under normal water conditions in almost all time periods.

Q. You have shown support for market-based methods of setting avoided cost. Are there reasons why Idaho might validly chose an administrative method?

A. I have suggested that simply paying market prices might not be acceptable to FERC and that the RFP/auction method is of questionable applicability in the face of excess capacity and energy. I also recognize that movement to market-based methods would be a very large change from Idaho's current practices. In my experience, regulation usually changes on a more evolutionary basis. Hence, while I believe that the market solutions merit serious consideration in Idaho, I observe that this is not the current expectation as is shown by the fact that this proceeding is focused on improving Idaho's avoided cost calculation methods using methods other than market price discovery.

VI. SUGGESTIONS CONCERNING AVOIDED COST PRICING BASED ON ADMISISTRATIVE METHODS

Q. Assuming that the Idaho Commission wishes to continue to set avoided costs administratively, what suggestions to you have?

A. My first suggestion is that it should rely on the IRP-type of calculation. I make the following suggestions for the how the IRP-type of avoided cost calculation could be conducted:

1. Avoided cost calculations should be based on the specific characteristics of the QF, not on the costs of a proxy unit.

2. Set schedules should be made available only for small units. Avoided costs for these schedules for smaller resources should be based on IRP analyses for generic versions of that type of resources. At a minimum, Idaho should have generic avoided costs for wind, photovoltaic solar, cogeneration (and other baseload fueled projects), and irrigation-based hydro.

3. Calculations of energy value should be based on the latest available information, not frozen for extended periods. Offering prices based on non-current forecasts will cause either a flood or dearth of offers depending on the direction of changes.

4. The model used to forecast energy prices should be updated as appropriate to reflect the

amount of QF capacity that is in process. Additions of QF capacity that are must-take or inframarginal, as is the case for the types of QFs being offered in Idaho, displace higher cost units and hence result in lower system marginal costs. Including previously contracted QFs in the model used to predict avoided energy costs makes avoided cost calculation more current and accurate and has the salutary effect that if a glut of QFs materializes due to too favorable avoided cost offers, the resultant drop in prices should help to moderate the glut.

5. For quite large increments of capacity (either individual projects or aggregates of projects), the effect of the resource on marginal costs and the need for capacity should be taken into account. This suggests an IRP-type of "with and without" simulation rather than the static "without" simulation to determine energy costs that is adequate and appropriate for small QFs.

6. If Idaho retains long-term or even intermediate-term contracts with predetermined prices, it is important that customers not take on price and marketability risks for power that is not economically or operationally useful on the utility's system. PURPA does not require that off-system sales revenues be factored into avoided costs and it is improper for customers to shoulder such risks for power that does not benefit them.

7. The capacity cost component of avoided cost should be based on the cost of the resource with the lowest net cost, net cost being computed based on its fixed costs offset for net contributions earned from providing energy and ancillary services, if any. Normally the correct unit will be a simple cycle combustion turbine, though in some circumstances it has been shown to be a different type of unit.[36]

8. The appropriate maximum project size at which fixed schedules are offered to QFs (presently, 100 kW for wind and solar and 10 aMW for other types of QFs) should be kept low, especially if Idaho continues to use a single SAR-based schedule for small QFs. Conversely, it may be reasonable to somewhat relax the size limit if the single SAR schedule is replaced by multiple, IRP-based generic schedules for the individual types of QFs.

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[36] As explained previously, the cheapest form of capacity (other than, perhaps, some forms of demand response) is a simple cycle peaker. However, other units may be cheaper forms of capacity if their higher cost is more than off-set by their higher value in producing energy and ancillary services. The three northeastern RTOs, which have capacity markets, derive the starting point for determining a capacity price based on the "net cost of new entry." This is the annual fixed cost of the unit, minus the difference between the revenues it would earn for selling energy and ancillary services and the variable cost of providing them. At times, this revenue offset has been large enough for combined cycle units that they have been the new entry, unit, since their net cost is below the net cost of the peaker. I also noted previously that capacity costs used for avoided cost purposes sometimes do not offset costs with energy and ancillary services value. This is conceptually wrong, but may be acceptable factually where and when peakers earn negligible margins. Conversely, where old and inefficient units are marginal much of the time, in New York City for example, the offsets are quite important.

9. All calculations need to take into account whether the utility needs, or even can absorb the energy and capacity from the QF. If QF procurement cannot be cut off entirely when no resources are needed, avoided costs should reflect the lack of need. At a minimum, the capacity value component of avoided cost should be adjusted to reflect a low to zero capacity value for unneeded capacity.

Q. In your discussion of the lessons learned from PURPA experience, you stated that the most important source of excess costs being imposed on utility customers came from large amounts of power purchased under long-term contracts at prices that were fixed at levels that turned out to substantially exceed avoided costs. Do you have any recommendation concerning contract length?

A. Yes. Long-term contracts with prices, particularly energy prices, set for long durations should be avoided. PURPA does not require that contracts of any particular term length be offered. However, if long-term contracts are offered, the QF gets to choose whether it wants to be paid avoided costs computed at the time of the contract or avoided costs computed at the time of delivery.

PURPA and the FERC regulations also are silent on the type of price offer that must be made at the time of contracting. The long-term offer, if made, presumably could be either a fixed schedule of prices or a formula rate (as FERC suggested in the Avoided Cost NOPR). A formula rate could, for example, be wholly or partially indexed to gas prices. Indeed, my understanding is that the current Idaho avoided cost rates for fueled projects are of this nature. Clearly, a formula rate linked to the cost of the power purchases or fuel that is actually avoided due to QF purchases is both more appropriate under PURPA and less risky for customers.

Q. QF developers contend that long-term contracts are essential since without assured revenues, the projects cannot be financed. If long-term fixed prices are not offered, does this mean that no one will build QFs in Idaho?

A. Not necessarily. It is not actually true that non-utility generation, including QFs, will not be built without long-term contracts with fixed prices. There are numerous examples of EWGs that are financed and built without such contracts. Indeed, some are being built in the exempt regions without bilateral contract support. What is actually complained of by developers is that the lack of such contracts raises financing costs. A secure and predictable revenue stream allows new facilities to be project financed with high leverage and low debt costs. In effect, the utility signing such a contract is absorbing the financial risks of the project by guaranteeing a revenue stream that may greatly exceed actual value or, at a minimum, is substantially more certain than the fluctuating value of energy in today's volatile power markets. Project risk is thus shifted from the developer and lenders to the utility and its shareholders and ratepayers. For QFs (and distinct from EWGs), the risk is shifted entirely to ratepayers since, by law, prudently incurred costs of PURPA power must be passed through in rates.

PURPA does not require, and I can think of no justification for, Idaho utilities' customers absorbing the risks that lenders to QFs arguably will not. The risk that long-term fixed prices may prove to have been substantially mis-forcast is the greatest problem with PURPA implementation. Long-term contracts at predetermined prices are the main reason why many contracts signed in the 1980s resulted in windfall gains for developers and excessive cost for ratepayers. Fuel prices had been expected to continue to escalate, but actually declined. I note that Idaho, at the time, adjusted its contract terms to reflect this lesson. The contract term for Idaho standard offers was reduced from 35 to 20 years in 1987 to reduce this forecast uncertainty. It subsequently was reduced to 5 years. In 2002, the maximum contract term was increased back to 20 years, notwithstanding that then-recent experience demonstrated the huge risks involved in setting prices based on forecasts of fuels prices over long periods.[37]

As I have discussed, the perception in the 1980s that contract prices were well above market and likely to be reduced as regulators lowered fuels forecasts contributed to a gold rush of unneeded power, exacerbating the cost impacts on mis-forecasting. A similar situation appears to be occurring now, as gas prices forecasts have been lowered and then lowered again and again as forecasters have come to better understand the impact of new technology for recovering shale gas on gas supplies and prices.

Q. Are there other reasons why Idaho is vulnerable today to too-high prices for QF power?

A. Yes. For certain types of resources, some areas of the country are much better than others. Wind, solar, and small hydro are obvious examples. To focus on

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[37] Idaho avoided cost rates for non-fueled projects that were in effect just prior to Decision 29124 in 2002 were assumed to increase by 6 percent per year from a base of $5.23/mmBTU. In that decision, the forecast was reduced to an escalation rate of 2.6 percent from a base of $3.75/mmBTU. Obviously, such a difference has an enormous impact. The fuel cost of the 7100 BTU heat rate unit adopted in that proceeding for the proxy unit would escalate to $66.4 per MWh in 10 years based on the then-preexisting assumptions versus $33.4/MWh under the new assumptions. After 20 years, the fuel costs would be $118.4/MWh under the prior assumptions and $44.8/MWh under the assumptions adopted in 2002. Current fuels prices and forecasts suggest that even the lower of these forecasts was too high.

wind, the best wind regimes are primarily in the Pacific Northwest and northern Midwest (and to a lesser degree, the northeast) and in areas like Oklahoma and the Texas panhandle. An examination of installed wind power demonstrates that Idaho has in the past been only one of several good locations. However, most of the states mentioned as good wind regimes, outside of the Pacific Northwest, are now exempt from PURPA. Developers seeking PURPA contracts have much narrower markets. The exemption of utilities in previously attractive markets may be one reason for the surge of contract requests in Idaho in 2010.

Q. If the avoided cost rates and contract terms offered in Idaho are made less attractive, what will happen?

A. This depends partly on what happens in other states. QF developers today are essentially balance sheets looking for profitable investments, wherever they can be found. If Idaho offers lower prices and/or less attractive contract terms than other states, QF developers may choose to build in those states. This is not necessarily a bad thing. A state that pays too much for QF power will not only overpay, but also attract unneeded capacity. This is the strong lesson learned from the New York and California experiences in particular. The large amount of QF power tendered to IPC suggests that it may be a recent lesson for Idaho.

Q. Does eliminating long-term fixed prices only protect customers?

A. No. As events unfolded in the past, fuel costs were much lower than the forecast costs embedded in fixed contract prices, so that contracts were very profitable to developers who bought cheap gas and sold power at prices that had been set assuming expensive gas. However, had events been different, with gas prices well above the forecasts fixed into contracts, the roles would have been reversed. The cogenerators who sold at fixed prices would have had to buy gas at prices well in excess of the prices implicit in the QF energy price. Such QFs easily could have lost money on every kWh generated and would have soon been bankrupt.

Q. What do you suggest is the appropriate way to treat contract length and firmness?

A. Contract lengths should be quite limited if fixed prices are used. One possible limit is the length of time for which Idaho utilities can hedge the value of the power that they purchase by engaging in off-setting bilateral sales contracts elsewhere. This would be particularly appropriate if, contrary to what IPC is seeking to achieve with its proposal, the Idaho utilities are required to contract for QF power that they do not need and will have to sell into interchange markets during much of the contract term with customers taking the price risk. A still short, but somewhat longer, contract term could be appropriate for QFs that actually can be absorbed by the host utility's load.

Contract length can be limited directly, or by limiting the period of time for which prices are firm. If the firm period is less than contract length, the contract can specify how prices will be reset in the future.

Q. Is it the case that short contracts create stranded asset risks for developers, in that the developer may not have a customer to whom power can be sold once the contract is over?

A. That is a theoretical risk, and may not even be merely theoretical for EWGs that do not have access to competitive markets. However, so long as Idaho utilities are not exempt from PURPA Section 210 obligations, their obligation to buy the output of QFs remains. A QF with an expiring contract is entitled to a new contract from its interconnected utility.

It is possible that changed circumstances or federal law may cause the Idaho utilities to become exempt from PURPA Section 210 responsibilities sometime in the future. However, under PURPA as modified by EPAct, exemption requires satisfying FERC that QFs will have access to a competitive market into which they can sell power. Exemptions therefore will not be granted if there is any material risk that QF assets will be stranded.

Q. Are you as concerned about fixing long-term prices for capacity as you are for energy?

A. No. Technological change and changes in financing costs can create a mismatch between avoided capacity cost estimates and outcomes.[38] However, building new, long-lived utility plant always entails these risks. Moreover, the variability in outcomes for capacity cost and value are considerably less than for energy.

Q. If the Idaho Commission decides that it wants to require long-term QF contracts with terms set at the time of signing, what terms can be used to limit risks to the utilities' customers?

A. Fixing terms at the time of signing does not necessarily require fixing prices. Other than provisions calling for periodic resetting of prices, the obvious alternative for reducing customer risk is price indexation. One option is to index prices to power prices in adjacent markets. I have discussed instances where this is done.

[38] The previous footnote illustrated the change in Idaho avoided cost parameters relating to fuels markets in 2002. In comparison, fixed costs relating to capacity were little changed, with the capital cost of the combined cycle unit declining somewhat in real terms and the fixed operations and maintenance rate increasing somewhat.

An alternative which is only modestly less useful is to index energy prices at least partly to natural gas prices. Prices in Northwest energy markets are, at least much of the time, based on prices into California. In turn, California prices are set based on the cost of gas most of the time, other than during the spring run-off affecting Northwest and California hydroelectric generation. For this reason, indexing contract energy costs to actual gas prices reasonably assures that contract prices will not diverge greatly from the value of power in the marketplace and the prices at which Idaho utilities buy and sell power in northwestern markets, at least in periods other than times of peak water flow.

For the gas-fired cogenerators that historically were the bulk of QFs, indexed prices also reduced rather than increased risk since fuel-indexed rates caused energy payments to track their fuel costs, locking in capacity-related margins that pay most of construction-related costs. However, indexation does not protect margins for the non-gas fired generators that are the primary source of recent QFs in Idaho.

Q. Do you have any concluding comment on how PURPA avoided costs should be set and contracts formulated?

A. Yes. Consistency with the letter and intent of PURPA Section 210 requires state implementations with two, and only two consequences: assuring that QFs are not discriminated against, and protecting customers by limiting payments to be no higher than the utility's avoided cost. PURPA was not, and is not, intended to guarantee that QFs will be profitable, or even that they will be built.

It is likely that resetting prices to reflect lower fuel price escalation expectations and the existence of excess capacity in the state and reducing the scope of price guarantees will result in lower amounts of QF power being offered in Idaho than has been offered in recent years. This is an appropriate outcome and is fully consistent with the letter and intent of PURPA. If Idaho determines that it needs more renewable generation than PURPA produces, there are other policy tools that can be used to cause renewable generation to be constructed, including, for example, set-aside procurements limited to renewables such as were approved in the past year for California.

Q. Does this complete your testimony at this time?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

HIERONYMUS, DI TESTIMONY

EXHIBIT NO. 6

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William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the economics, structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last twenty years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his thirty-odd years of consulting to this sector, he also has performed a number of more specific functional tasks, including analyzing potential investments; assisting in negotiation of power contracts, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, arbitrators and legislative bodies in the United States, the United Kingdom and Australia. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus serves as an advisor to the senior executives of electric utilities on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. Related to some of these assignments, he has testified before state agencies on regulatory policies and on contract and asset valuation.

- For utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers on which he has testified are Duke-Progress, Duke-Cinergy, NSTAR-Northeast Utilities, Sempra (Enova and Pacific Enterprises), Xcel (New Century Energy and Northern States Power), Exelon (Commonwealth Edison and Philadelphia Electric), AEP (American Electric Power and Central and Southwest), Dynegy-Illinois Power, Con Edison-Orange and Rockland, Dominion-Consolidated Natural Gas, NiSource-Columbia Energy, E-on-PowerGen/LG&E and NYSEG-RG&E, Iberdrola-Energy East, Texas Energy Futures-TXU, Exelon-NRG, GDF/Suez and FirstLight and MacQuarie-Puget Sound. He also submitted testimony in mergers that were terminated, usually for unrelated reasons, including EEG (Exelon and PSEG), Constellation-FPL Energy, Entergy-Florida Power and Light, Northern States Power and Wisconsin Energy, KCP&L and Utilicorp and Consolidated Edison-Northeast Utilities. Testimony on similar topics has been filed for a number of smaller utility mergers and for numerous asset acquisitions. Dr Hieronymus has also assisted numerous clients in the pre-merger screening of potential acquisitions and merger partners.
- For utilities seeking to establish or extend market rate authority, Dr. Hieronymus has provided scores of analyses concerning market power in support of submissions under Sections 205 and/or 206 of the Federal Power Act.
- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and revenue adequacy and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the market performance, and achievement of the client's objectives. In some cases, these analyses have led to testimony and/or participation in stakeholder processes.
- For generators and marketers, Dr. Hieronymus has testified extensively in the regulatory proceedings concerning the electricity crisis in the WECC that occurred during the period May 2000 through May 2001. His testimony concerned, inter alia, the economics of long term contracts entered into during that period the behavior of market participants during the crisis period and the nexus between purportedly dysfunctional spot markets and forward contracts. He also provided testimony and other regulatory support in dockets concerned with economic and physical withholding, partnership arrangements and bidding and scheduling practices potentially in violation of the ISO tariff.
- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC and in ISO-New England's market power mitigation rules.
- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.
- For both utilities and generators he has testified on a number of occasions on market mitigation rules for the New York City load pocket and their relationship to policy goals such as market-based entry.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.
- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.
- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.
- He has testified concerning the value of terminated long term contracts in connection with contract defaults by bankrupt power marketers and merchant generators.
- In connection with the Western U.S. long term contracts proceeding, he testified with respect to benchmarking of contracts and to the relationship between market prices and long run marginal costs of new generation.

Other U.S. Utility Engagements

- In a recent arbitration proceeding, Dr. Hieronymus testified with respect to contract terms relating to security provisions for long repaying front-end loaded contract payments.
- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.
- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.
- He has made numerous presentations to U.S. utility managements regarding overseas electricity systems and market reforms.
- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that were then under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders. For the senior managements and boards of utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction.
- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.
- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.
- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.
- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system.
- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

U.K. Assignments (1988-1994)

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional distribution and retail supply companies focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.
- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing commercial capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.
- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.
- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.
- He assisted one of the Regional Electricity Companies in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus testified before the federal court of Australia concerning the market power implications of acquisition of a share of a large coal-fired generating facility by a large retail and distribution company.
- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the EU directive on electricity that *inter alia* required retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.
- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.
- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.
- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command- and-control system to a decentralized, corporatized system.
- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.
- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.
- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.
- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.
- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.
- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.

- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.
- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section I33.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed a basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.
- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.
- For state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.
- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus assists clients in Hart-Scott-Rodino investigations by the Antitrust Division of the U.S. Department of Justice and the Federal Trade Commission. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality. In two Surface Transportation Board proceedings, he testified on the sufficiency of product market competition to inhibit the exercise of market power by railroads transporting coal to power plants.
- For one owner of the Trans-Alaskan Pipeline, he submitted testimony to FERC in 2010 concerning cost pooling and related issues of cost and revenue allocation among co-owner.
- For a landholder, Dr. Hieronymus examined the feasibility and value of an energy conversion project that sought a long-term lease. The analysis was used in preparing contract negotiation strategies.
- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has been an invited speaker at numerous conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervener strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.

Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate and Program Manager for Energy Market Analysis at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 31st day of January 2012 I served a true and correct copy of the DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS upon the following named parties by the method indicated below:

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